ANNUAL REPORT 2002

Our royalty lands are a distinguishing feature and provide a clear advantage within the energy trust sector. These lands continue to be a major contributor to our operating and financial performance, helping to generate a total return to Unitholders of 33% in 2002.

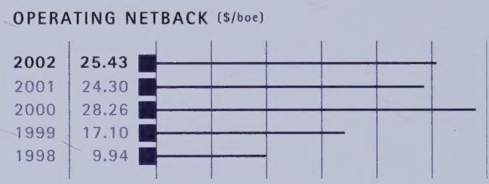
Freehold
ROYALTY TRUST

THE ROYALTY ADVANTAGE

THE ROYALTY ADVANTAGE

A royalty interest offers the benefit of sharing in production, without exposure to the capital costs, operating costs and environmental costs associated with oil and gas production. Compared with working interests, royalty interests have higher netbacks.

Royalty production results in higher netbacks to Unitholders.



ROYALTY INTERESTS VERSUS WORKING INTERESTS

Freehold owns both royalty and working interests, but the majority of its production comes from royalties.

There are two types of ownership in oil and gas reserves – working interests and royalty interests. Working interests are participating (lessee) interests in land, and are expressed as a fraction or a percentage. Working interest owners pay capital and operating costs and pay royalties to the mineral title owner. Royalty interests are interests in production (or production income) only. A royalty is a payment made from the gross production at the wellhead and the royalty owner is not responsible for any of the capital or operating costs required to deliver the oil or gas at the wellhead.

TYPES OF ROYALTY INTERESTS

Freehold owns both mineral title rights and gross overriding royalties, but the majority of its royalties are mineral titles which are held in perpetuity.

There are two types of royalty interests – lessor royalties and overriding royalties. Lessor royalties represent the mineral title owner's share of production, free of expense of the production. Overriding royalties arise primarily from contractual arrangements between companies and are usually derived from working interests that would expire when production ceases.

HOW ROYALTIES ARE CALCULATED – EXAMPLE

A contract (lease agreement) is entered into between the party that owns the mineral rights (lessor) and the party that wants to drill for oil and/or gas (lessee) in exchange for payment of a royalty. Royalty rates vary from lease to lease.

The working interest owner (lessee) drills for oil and/or gas. If the drilling results in a successful oil or gas well, then the lessor receives a royalty based on that production. For example, if the royalty rate as stipulated in the lease is 20% and a well is drilled that produces 100 barrels per day; the royalty owner receives 20% of 100 barrels (i.e. 20 barrels) or the cash equivalent. This will continue until the well no longer produces.

TOP ROYALTY PAYORS (For the year ended December 31, 2002)

The majority of royalties owned by Freehold are lessor's royalties, based on Freehold's mineral title ownership. Freehold has 4,100 lease agreements in place and receives royalty payments on more than 15,000 producing wells from over 180 operators. The royalty rates vary from less than one percent (for some gross overriding royalties) to 20% (for lessor royalties).

During 2002, the following companies were Freehold's top fifteen royalty payors. These companies accounted for approximately 70% of Freehold's royalty income.

Apache Canada Ltd., Bison Resources Ltd., BP Canada Energy Company, Canadian Natural Resources Limited, ConocoPhillips Canada, Devon Canada Corporation, EnCana Corporation, Murphy Oil Company Ltd., Husky Oil Operations Limited, Nexen Canada Ltd., Northrock Resources Ltd., Shell Canada Limited, Talisman Energy Inc., Upton Resources Inc., and Vintage Petroleum Canada, Inc.

CORPORATE PROFILE

Freehold Royalty Trust has the royalty advantage. The Trust is one of the largest owners of privately-held mineral rights in western Canada. These royalty-generating properties provide income from the production and sale of crude oil, natural gas, natural gas liquids and potash. This royalty production is not subject to major expenses such as operating and capital costs or environmental liabilities.

The Trust collects and regularly distributes income to Unitholders. Freehold's objective is to provide investors with superior returns and consistent distributions primarily from its royalty-generating assets. Growth in the underlying value of the Trust is achieved through ongoing development activity on the land base and the acquisition of new oil and gas assets.

Freehold's Trust Units trade on the Toronto Stock Exchange under the symbol FRU.UN.

Freehold distributed $1.31 per Trust Unit to Unitholders in 2002 representing a 12% cash on cash return.

HIGHLIGHTS

Financial ($000s, except unit data)	2002	2001	% Change
Gross revenue	**63,143**	61,885	2
Distributable income	**39,530**	45,264	(13)
Per Trust Unit ($)	**1.31**	1.56	(16)
Capital expenditures	**2,946**	2,992	(2)
Long-term debt	**30,000**	33,000	(9)
Unitholders' equity	**185,480**	196,442	(6)
Trust Units outstanding	**30,225,236**	30,129,236	–
Weighted average	**30,165,167**	28,839,216	5

Operating			
Production			
Oil (bbls/d)	**3,926**	3,873	1
NGLs (bbls/d)	**288**	354	(19)
Natural gas (mmcf/d)	**10.7**	11.2	(4)
Oil equivalent (boe/d)[1]	**6,004**	6,086	(1)
Average sales price			
Oil ($/bbl)	**31.25**	24.42	28
NGLs ($/bbl)	**25.09**	29.91	(16)
Natural gas ($/mcf)	**3.81**	5.64	(32)
Oil equivalent ($/boe)[1]	**28.44**	27.63	3
Established reserves (mboe)[1]	**26,813**	28,177	(5)
Undeveloped land (gross acres)	**235,062**	237,443	(1)

1 In order to provide a single unit of production for analytical purposes, natural gas is converted to equivalent barrels of oil (boe). Freehold uses the international conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl). The boe ratio approximates an equivalent energy value, useful for comparative measures, but may not accurately reflect individual product values.

FREEHOLD'S ROYALTY INCOME STREAM PROVIDES *the most pure form of royalty income investment in the Canadian oil and gas sector.*

PRESIDENT'S MESSAGE

In last year's annual report, we said that cash distributions for 2002 would be approximately $1.00 per Trust Unit, based on production of 6,000 boe per day and certain assumptions for commodity prices. I am pleased to report that we achieved our production forecast and distributed $1.31 per Trust Unit in 2002, exceeding our initial estimate by a substantial margin. The increase in distributions is entirely attributable to higher commodity prices than we had anticipated.

Drilling on Freehold's lands was 15% higher than last year, despite an overall slowdown in industry drilling. Some of this activity took place in the latter part of the year and the results from these wells are not fully reflected in our year-end reserve estimates or production results.

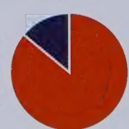
We completed two acquisitions and one property swap for $2.3 million, which will add approximately 100 boe per day to the Trust's royalty production in 2003. We actively pursued several opportunities that met our investment criteria but were unsuccessful in completing a substantial acquisition.

Lack of a significant acquisition in 2002 contributed to a 5% decline in established reserves (proven plus risked probable) to 26.8 million boe. Nonetheless, the Trust's reserve life index remains at more than 12 years.

In 2002, 86% of distributable income came from royalty production.

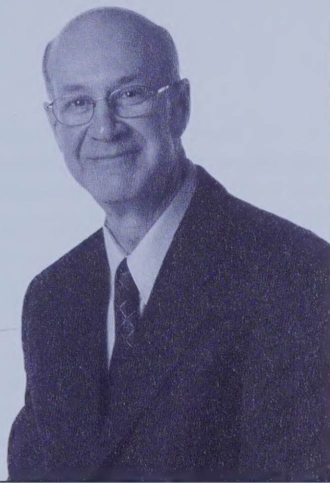
2002 DISTRIBUTABLE INCOME BY SOURCE (%)

Royalty Production	86
Working Interest Production	14



OUR STRATEGY

Freehold's royalty assets are integral to the strategy of the Trust. In excess of 86% of distributable income is derived from mineral title and gross overriding royalties, the majority of which the Trust owns in perpetuity. Ongoing development by lessees has added production and reserves every year since inception – at no cost to the Trust. This activity, which we refer to as "free drilling", now provides about 25% of Freehold's royalty production. Managing these royalty assets requires a special diligence, including an aggressive audit program to ensure that royalties are correctly calculated and paid when new wells are drilled and that these royalties continue to be paid to the Trust if the properties are transferred to new operators.



David J. Sandmeyer
PRESIDENT & CHIEF EXECUTIVE OFFICER

Since inception in November 1996, we have consistently executed our strategy, actively managing the Trust's assets to sustain reserves and productivity. The goal is to extend cash distributions over the long-term, primarily by acquiring appropriate reserves and production that increase the value per Trust Unit. In fact, Freehold has only issued new equity to the public once (in 2001) since inception.

Our strategy is to actively manage the Trust's assets to sustain reserves and productivity per Trust Unit over the long-term, in order to extend cash distributions further into the future.

Acquisition Strategy

All oil and gas trusts look to acquire additional assets to replace declining reserves and production. Freehold actively seeks to purchase producing properties, with a bias towards acquisition of royalty interests. However, subject to threshold requirements in terms of cash flow, return on investment, reserve life and future development potential, the Trust may also pursue working interest properties and/or corporate acquisitions.

We believe that continued industry consolidation will create acquisition opportunities that are attractive to Freehold. Our challenge is to identify and capitalize on those opportunities that will add value, on a per Trust Unit basis. To this end, we have strengthened our acquisition group to improve our success.

A Strong Balance Sheet

The Trust has a conservative net debt-to-cash flow ratio of 0.4:1, one of the lowest in the energy trust group. This balance sheet strength is a key component of Freehold's strategy to pursue acquisition opportunities. It provides considerable leverage, offering the flexibility to fund acquisitions with available credit facilities without the need to immediately issue new equity.

MANAGEMENT OF THE TRUST

The goals of the Trust are supported by a proven management team. Each individual in this group has more than 20 years of experience managing the Trust's initial assets.

Freehold is conservatively managed by experienced people and has quality assets with the long-term capability to deliver income.

The elimination of contracts for outside managers of oil and gas trusts was a major trend that began in 2002. Freehold's Board has discussed internalizing management with respect to Freehold and has decided to make no move in that direction, for three reasons. First, the management fees paid to the Manager continue to be among the lowest in our peer group. In 2002, management and acquisition fees were $1.0 million and for the six-year life of the Trust, a modest $5.3 million. Second, Freehold pays its management fees in Trust Units, which clearly aligns the interests of the Manager with the interests of the Unitholders. Third, the management company that is responsible for Freehold's operations also manages the business of two other private corporations and the synergy available by having a larger, more diversified staff to manage the assets of Freehold is advantageous to Unitholders.

The Board has addressed potential conflicts of interests of the Manager (which arise primarily out of acquisition activity) through an understanding between the private companies and the Trust. This arrangement provides for a sharing formula for any acquisitions completed by the Manager on behalf of the Trust. Further, all major acquisitions require Board approval.

2003 OUTLOOK

The Canadian Association of Oilwell Drilling Contractors forecasts an 11% increase in industry drilling in 2003, approaching the number of wells drilled in 2001, which was a record year. As drilling on Freehold's royalty lands generally mirrors industry levels, we anticipate an active year for Freehold as operators continue with drilling programs on our royalty lands. Our own capital program (for our working interest properties) has been expanded to $4.6 million, with approximately 30 wells planned. This activity will help to sustain our production and reserves in 2003.

Speculation of U.S.-led military action against Iraq, combined with the political conflict in Venezuela that began in December, has disrupted oil production, significantly tightening global supplies and creating a war premium for oil. We believe that stability will return to the political climate with respect to energy supply and anticipate some weakening in oil prices as the year progresses. The price outlook for heavy oil is positive as a result of a return to supply/demand balance in mid-2002. There is a shortage of natural gas production and gas storage levels are low. Therefore, we believe that natural gas, as a North American commodity, has greater stability in terms of short-term pricing.

Early indications from policy commitments are that Canada's ratification of the Kyoto Protocol will not significantly penalize the oil and gas industry. Some uncertainty will remain until the Federal government provides its detailed implementation plan and it becomes clearer what the effect will be on business economics, primarily on the cost side. However, we do not expect ratification of the accord to have a material effect on our performance in 2003.

Hedging

We believe that Unitholders have invested in Freehold for income, but also to participate in the commodity price cycles. While hedging may be used to attempt to equalize distributions, there is an opportunity cost in terms of distributable cash if the right hedging decisions are not made. Therefore, it has been Freehold's position to accept prices in the market and our production remains unhedged. This policy is subject to regular review by the Board of Directors.

Distributions

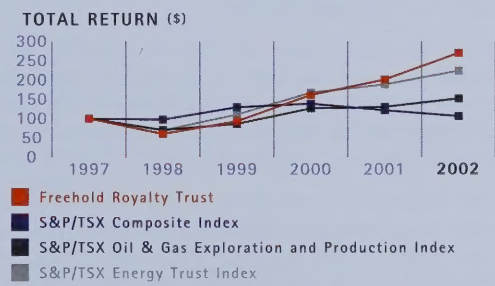
In the absence of acquisitions, we expect that, due to normal production declines, production volumes will decline modestly in 2003 to average 5,800 boe per day for the year.

Our 2003 budget anticipates that commodity prices will average Cdn. $5.00 per mcf for natural gas and U.S. $25.00 per barrel for WTI crude oil, with light/heavy oil differential prices averaging Cdn. $8.00 per barrel. Based on these assumptions, we estimate that approximately $1.40 per Trust Unit will be distributed to Unitholders in 2003.

In providing this guidance to our Unitholders, we use our internal estimates to establish a sustainable regular distribution – which right now is set at $0.10 per month. On a quarterly basis, we review our performance and future revenue assumptions and the Board determines if an adjustment is required. At the Board's discretion, a portion of income in excess of regular distributions may be directed toward repayment of long-term debt and/or working capital improvement with the remainder delivered to Unitholders in the form of a special quarterly distribution.

In 2002, Freehold generated a total return to Unitholders of 33%[1], well above the comparable benchmark indices.

1 Year-over-year appreciation in Trust Unit price plus distributions of $1.31.



ACKNOWLEDGEMENTS

I would like to thank our Unitholders for their continuing support and our Directors for their unwavering commitment to governance and management principles.

As a final note, I would like to acknowledge the employees of the Manager, Rife Resources, most of whom have been with the Trust since its inception. Our employees take personal pride in managing the assets of the Trust to deliver value to our Unitholders. Their continuing efforts and dedication will ensure that Freehold continues to be a sound, rewarding investment for Unitholders with regular distributions, an exemplary balance sheet, and the royalty advantage.

David J. Sandmeyer
PRESIDENT & CHIEF EXECUTIVE OFFICER

March 18, 2003

The corporate governance structure of a trust is not the same as for a conventional corporation. The Trust holds royalties, including a royalty granted by Freehold Resources Ltd. (the operating company), with certain rights under a Trust Indenture, a Unanimous Shareholder Agreement and a Management Agreement. The Trust has no directors. The Board of Directors of Freehold Resources Ltd. has a mandate to supervise the management of the business and affairs of the Trust in the best interests of the Trust. The Trust is managed by Rife Resources Management Ltd.

The Trust is governed by the Board of Directors of Freehold Resources Ltd.

BOARD COMPOSITION AND INDEPENDENCE

Unitholders are entitled to elect the majority of the Board of Directors of Freehold Resources Ltd. The Board of Directors consists of seven members, the majority of whom are considered "outside" and "unrelated" directors as those terms are defined in the TSX Guidelines.[1] Two members are considered "inside" and "related" directors. The other five members are "outside" directors (i.e. they are not officers or employees of Freehold Resources Ltd. or the CN Pension Trust Fund[2]). Four of the "outside" directors are "unrelated" directors. The Board of Directors of Freehold Resources Ltd. has functioned, and is of the view that it can continue to function, independently of the Manager[3] and the CN Pension Trust Fund. The Chairman of the Board is an "outside" and "unrelated" director.

RELATIONSHIP WITH THE MANAGER

The Board, in conjunction with the Manager, is responsible for the strategic planning process, identifying the principal business risks of the business and implementing appropriate systems to manage these risks, the communication policy for the Trust, the integrity of internal controls and management information systems.

The Manager is responsible for the day-to-day management of the business of the Trust. This includes management of the properties and advice with respect to acquisitions, dispositions, and the development of the properties. The Manager makes available office space, equipment and all management and administrative personnel; provides or arranges for audit, accounting, engineering, legal, geological, geophysical, financial, insurance and other professional services or advice as are required. The Manager administers all matters pertaining to the Trust Units, including determining amounts owing to Unitholders, arranging for distributions and providing periodic reports, tax information and consolidated financial statements to Unitholders. The Manager is paid a management fee and is entitled to reimbursement for general and administrative costs that are incurred to manage the Trust.

The Board is responsible for supervision of the Manager. In particular, the Board must approve significant operational decisions; issuances of additional Trust Units; acquisition and disposition of properties in excess of $5.0 million; capital expenditures outside of approved budgets; establishment of credit facilities; and the payment of distributable income.

1 Section 474 of the TSX Company Manual sets out guidelines for effective corporate governance. Some of the terms used in Section 474 are summarized below:
Unrelated Director: A director who is independent of management and is free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the corporation, other than interests and relationships arising from shareholding.
Related Director: A director who is not an unrelated director.
Outside Director: A director who is a non-management director.
Inside Director: A director who is a member of management.

2 The CN Pension Trust Fund (the pension fund for employees of the Canadian National Railway Company) holds 31% of the Trust Units.

3 Rife Resources Management Ltd., the Manager of the Trust, is a wholly-owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Fund.

William W. Siebens[2] CHAIRMAN OF THE BOARD

Mr. Siebens brings special expertise to Freehold with his knowledge of the Trust's Hudson's Bay Royalty Lands as these lands were previously owned by Siebens Oil & Gas Ltd. He is President and CEO of Candor Investments Ltd. (Calgary), a private energy and investment corporation, and currently serves on the boards of several corporations.

D. Nolan Blades[1,2] CHAIR, AUDIT COMMITTEE

Mr. Blades is President of Sunny Gables Holdings Ltd. (Calgary) and a Professional Engineer with extensive experience in the oil and gas industry. Mr. Blades has held senior positions with Kaiser Oil Ltd., Oakwood Petroleums Ltd., and Chauvco Resources Ltd., and most recently was President and CEO of Pursuit Resources Corp.

The Audit Committee members are all outside and unrelated directors.

Harry S. Campbell Q.C.

Mr. Campbell is Managing Partner of the law firm Burnet, Duckworth & Palmer LLP (Calgary). He was admitted to the Alberta Bar in 1974. Mr. Campbell is currently a Director of DT Energy Ltd., TVX Gold Inc., and The Cathay Investment Fund Limited and has been a director of numerous private and public corporations.

Tullio Cedraschi

Mr. Cedraschi is President and CEO of the CN Investment Division (Montreal). He is currently a Director of the Toronto Stock Exchange, and serves on the boards of several corporations. He is a Governor and Past President of the National Theatre School of Canada and he is also a Governor of McGill University where he received his MBA.

Dr. P. Michael Maher[1,2] CHAIR, CORPORATE GOVERNANCE & NOMINATING COMMITTEE

Dr. Maher is a Professor and former Dean of the Haskayne School of Business of the University of Calgary. He has served on the boards of numerous corporations and public sector organizations. Dr. Maher received a Bachelor of Engineering degree, University of Saskatchewan; an MBA, University of Western Ontario; a Ph.D. from Northwestern University; a Doctor of Commerce (honoris causa) degree from St. Mary's and is a Professional Engineer.

The Corporate Governance and Nominating Committee members are all outside and unrelated directors.

Peter T. Harrison[1]

Mr. Harrison is Senior Vice-President of Montrusco Bolton Inc. (Montreal). Mr. Harrison has over 23 years of investment experience, and most recently managed Canadian Equities for the CN Investment Division. He holds a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario and is a Chartered Financial Analyst.

David J. Sandmeyer PRESIDENT & CEO

Mr. Sandmeyer is President of Rife Resources Ltd. (Calgary). He joined the Company in 1982. Prior to that he was employed with Amoco Canada Petroleum Company Limited for 18 years. Mr. Sandmeyer is a Governor of the Canadian Association of Petroleum Producers (CAPP). A graduate of the University of Saskatchewan, he holds a B.Sc. degree in Mechanical Engineering and is a Professional Engineer.

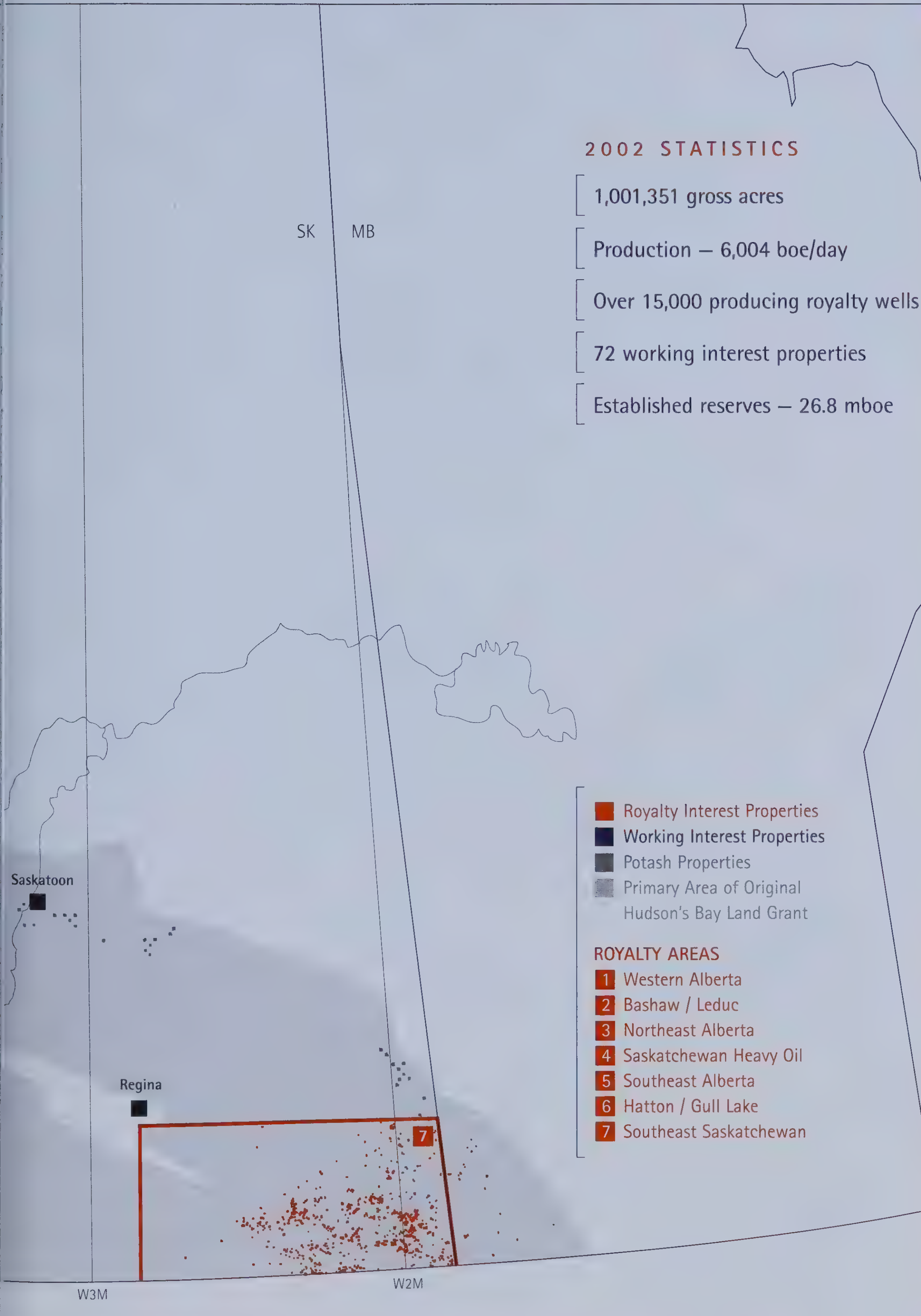
1 Audit Committee: The committee is responsible for reviewing the financial statements prior to their approval by the full Board. The audit committee also reviews the reserves on an annual basis. The committee meets with the auditors, independent reserves evaluator, and management of Freehold as part of this review process.

2 Corporate Governance & Nominating Committee: The committee is responsible for reviewing and recommending to the Board the remuneration of directors. The committee administers the Trust Unit Option Plan. The committee reviews corporate governance policies and practices and reviews/approves the Trust's disclosure policy. It also considers candidates for election as directors, annually recommends to the Board the slate of nominees for election to the Board by the Unitholders and recommends to the Board nominees to fill vacancies on the Board.

FREEHOLD'S TOTAL LAND HOLDINGS

2002 STATISTICS

- 1,001,351 gross acres
- Production – 6,004 boe/day
- Over 15,000 producing royalty wells
- 72 working interest properties
- Established reserves – 26.8 mboe



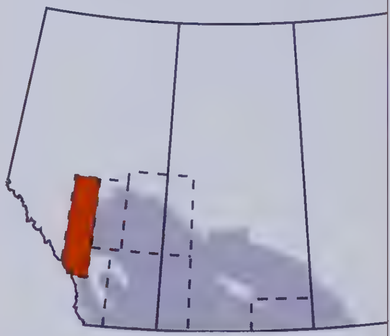
FREEHOLD ROYALTY AREAS

2002 Highlights

Royalty Areas	Land Holdings Total (gross acres)	Land Holdings Undeveloped (gross acres)	Wells Drilled (gross)	Production Oil & NGLs (bbls/d)	Production Natural Gas (mmcf/d)	Established Reserves Additions (mboe)	Established Reserves Total (mboe)
Western Alberta	88,525	15,540	31	333	2.4	13	5,373
Bashaw/Leduc	66,954	8,058	56	155	1.4	146	1,124
Northeast Alberta	122,343	17,300	38	500	0.9	73	3,147
Saskatchewan Heavy Oil	62,829	14,836	14	971	0.5	269	2,612
Southeast Alberta	127,451	11,173	317	140	1.2	104	1,553
Hatton/Gull Lake	125,581	24,426	72	130	0.6	50	1,166
Southeast Saskatchewan	130,442	97,981	69	563	0.2	183	1,696
Other	81,013	7,938	12	76	0.5	1	635
Total	**805,138**	**197,252**	**609**	**2,868**	**7.7**	**839**	**17,306**

WESTERN ALBERTA

In 2002 the most active operators were Apache, Comstate and Revolution.

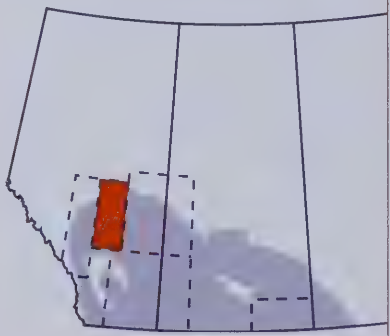


Western Alberta represents a wide distribution of producing fields from the foothills at Turner Valley, Jumping Pound West and Wildcat Hills to the northern plains at Whitecourt. Production from this area is primarily natural gas and light oil.

Production was down in 2002 due to normal declines and the effect of a two-year positive adjustment received in 2001 from the Caroline Swan Hills Gas Unit No. 1.

BASHAW / LEDUC

In 2002 the most active operators were Centrica, Devon and Apache.

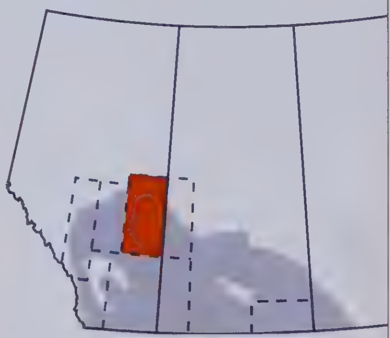


Bashaw / Leduc encompasses a wide diversity of productive zones from the Devonian Leduc Reef at a depth of 7,500 feet to the Upper Cretaceous Belly River at less than 2,500 feet.

Production increased from 2001 as a result of drilling – such as the six Viking oil wells (4.35% royalty) drilled at Redwater.

NORTHEAST ALBERTA

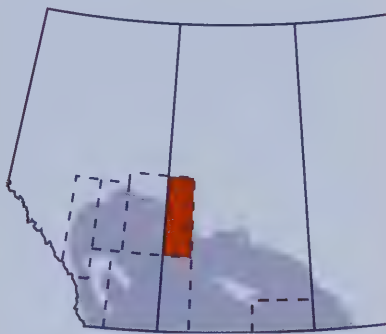
In 2002 the most active operators were Rife, Talisman and Husky.



The main producing horizons in Northeast Alberta are the Viking and Mannville formations. The northern part of the area is characterized by the production of heavier oil and/or gas from the shallow (less than 3,300 feet) Mannville sands. Significant production units are the Wildmere Lloydminster "A" Unit No. 1, David Lloydminster C. Waterflood Unit #1, three Chauvin South units and five Wainwright units.

Drilling activity and production in this area were up year-over-year.

SASKATCHEWAN HEAVY OIL

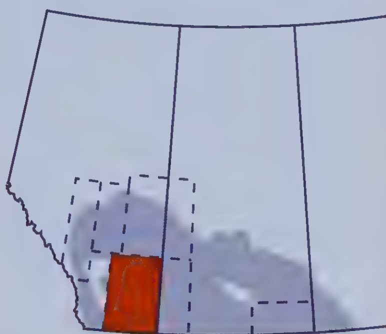


The major productive zones are the Mississippian Bakken, the Cretaceous Mannville and the Cretaceous Viking formations. Significant revenue properties are the Luseland and Hoosier Bakken pools, the Baldwinton and Tangleflags Sparky pools, and the Low Lake Waseca pool.

Production was up year-over-year due to drilling that occurred in 2001. There are currently 12 locations (12.5% royalty) on Section 26-45-23 (W3M) operated by Baytex.

In 2002 the most active operators were Murphy, Baytex, Nexen and Profico.

SOUTHEAST ALBERT

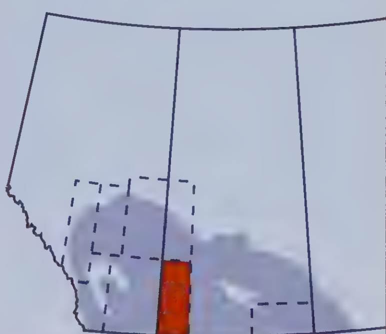


This area represents the largest number of gas wells for Freehold. Although shallow gas is the dominant play, oil production contributes significantly to revenue.

2002 drilling was primarily for shallow natural gas. 245 of the 317 wells drilled in 2002 were within units where Freehold holds a royalty interest.

In 2002 the most active operators were Enerplus, EnCana, Conoco, EOG and Advantage.

HATTON / GULL LAK

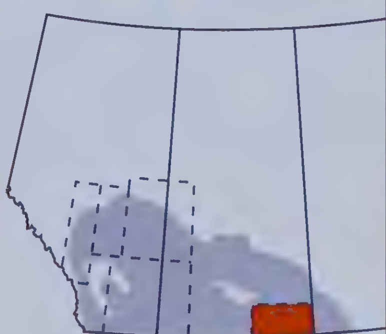


The Hatton/Gull Lake area of southwestern Saskatchewan provided revenue to Freehold from shallow gas production and from oil production from interests owned near Swift Current.

Similar to Southeast Alberta, drilling in 2002 was focused on shallow natural gas.

In 2002 the most active operators were Anadarko, Husky, Apache, Star and EOG.

SOUTHEAST SASKATCHEWAN



Southeast Saskatchewan, situated on the northern edge of the Williston basin, contains the largest amount of undeveloped land. In the past decade, horizontal wells have become the favored method of exploitation and account for the majority of production.

2002 was a very active year for the area in terms of drilling, primarily for light oil.

In 2002 the most active operators were Nexen, Bison, Talisman, Petrobank, Upton, APF and Tappit.

The following discussion and analysis should be read in conjunction with the audited combined financial statements and notes contained in this Annual Report. It offers the Manager's assessment of Freehold's future plans and operations and contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond Freehold's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Freehold's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated will transpire or occur, or if any of them do so, what benefits that Freehold will derive therefrom. Freehold disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

All comparative percentages are between the years ended December 31, 2002 and 2001 and all dollar amounts are expressed in Canadian currency, unless otherwise noted.

CONVERSION OF NATURAL GAS TO OIL EQUIVALENT

In order to provide a single unit of production for analytical purposes, natural gas production and reserves volumes are mathematically converted to equivalent barrels of oil (boe). Freehold uses the international conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl). The boe ratio approximates an equivalent energy value that is useful for comparative measures but may not accurately reflect individual product values.

SUPPLEMENTAL DISCLOSURE

Distributable income and income available for distribution are not recognized measures under Canadian generally accepted accounting principles. Management believes that in addition to net income and net income per Trust Unit, distributable income and income available for distribution are useful supplemental measures as they provide investors with information on cash available for distribution. Investors should be cautioned that distributable income and income available for distribution should not be construed as an alternate to net income as determined by Canadian generally accepted accounting principles.

FREEHOLD'S DIVERSE PRODUCTION BASE *includes significant mineral title and gross overriding royalties, which comprise the majority of the Trust's distributable income.*

OVERVIEW

A royalty trust is structured to return the majority of its income to Unitholders in a tax-effective manner. An energy trust receives cash flow from oil and gas properties as reserves are produced, which is paid to Unitholders on a regular basis over the economic life of the properties. Yet, without significant capital reinvestment to sustain oil and gas production, reserves are depleted over time and the cash flow is not maintained. Freehold Royalty Trust has a diverse production base (over 15,000 producing wells throughout western Canada) that includes significant mineral title and gross overriding royalties, which are responsible for the majority of the Trust's distributable income. These royalties are not subject to capital expenditures or abandonment liabilities. This royalty income results in superior netbacks, which maximizes distributable income to Unitholders. The Trust's long reserve life (12.2 years), low sustaining capital investment requirements and the fact that so much development occurs on Freehold's lands at no cost to the Trust make these assets very well suited to a royalty trust.

RESULTS OF OPERATIONS

The Trust's "mineral title lands" cover about 478,500 acres and the Trust has "gross overriding royalty" interests in approximately 326,600 acres. In addition, Freehold holds working interests in 196,212 (37,809 net) acres. As at December 31, 2002, the Trust's total undeveloped land position was 235,062 gross acres.

Acreage Summary (gross acres)	**2002**	2001	2000
Alberta	**632,047**	636,958	634,290
Saskatchewan	**341,134**	339,197	210,839
British Columbia	**25,946**	25,946	24,906
Manitoba	**2,224**	2,444	1,637
Total	**1,001,351**	1,004,545	871,672

DRILLING ACTIVITY

A total of 663 (17.65 net) wells were drilled on Freehold's lands in 2002, up 15% from 2001.

While drilling activity in western Canada declined 19% year-over-year, drilling on Freehold's lands increased 15% reflecting the Trust's favourable land position.

Drilling on royalty lands reached record levels in 2002. We call this "free drilling", since the Trust is not responsible for any drilling or development expenditures with respect to the royalty lands, but receives royalty income from successful wells.

Royalty Lands

Wells drilled by third party lessees on Freehold's royalty lands reached record levels in 2002. A total of 609 wells were drilled with a 98% success rate. During 2002, the Saskatchewan Heavy Oil and Bashaw/Leduc areas contributed the highest production additions from development and drilling activity.

Drilling on the royalty lands should continue to provide new sources of royalty income in future years as new wells reduce the rate at which production and royalty income would otherwise decline. Drilling on Freehold's royalty lands generally mirrors industry levels, which is expected to remain strong in 2003.

Wells Drilled on Royalty Lands (includes unitized wells)	**2002**	2001	2000
Oil	**193**	200	113
Natural gas	**363**	287	289
Service/other	**42**	21	20
Dry and abandoned	**11**	17	11
Gross wells	**609**	525	433
Success rate (%)	**98**	97	97

Working Interest Properties

Freehold participated in the drilling of 54 (4.9 net) wells during 2002. The success rate was 100% and reflects the conservative nature of the Trust's capital investment program, which excludes participation in high-risk exploratory drilling.

Wells Drilled on Working Interest Properties	**2002**		2001		2000	
	Gross	**Net**	Gross	Net	Gross	Net
Oil	**32**	**4.8**	23	2.5	49	8.2
Natural gas	**22**	**0.1**	27	0.9	20	0.2
Service/other	**–**	**–**	–	–	–	–
Dry and abandoned	**–**	**–**	–	–	2	0.2
Total	**54**	**4.9**	50	3.4	71	8.6
Success rate (%)		**100**		100		97

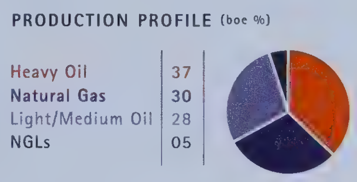
Freehold has working interests in 72 properties. Two properties, Hayter and Pembina Cardium Unit No. 9 (PCU #9) accounted for 40% of working interest production in 2002. Freehold owns 48.5% of the mineral title as well as a 23.5% working interest at Hayter, a heavy oil property located in east central Alberta. During 2002, a total of 10 wells (2.35 net) were drilled at Hayter. At PCU #9, a light oil property located in central Alberta, a total of 18 (1.8 net) infill wells were drilled during 2002. Freehold has a 0.6% royalty and a 9.9% working interest at PCU#9.

The majority of Freehold's $4.6 million capital program planned for 2003 will be invested on development projects at Hayter and PCU#9, and at Lashburn located in Saskatchewan. Up to 10 wells are planned at Hayter, two of which are to be drilled in the first quarter. In addition, water injection facilities at Hayter will be expanded to return shut-in wells to production. Thirteen wells are planned at PCU#9 during the first and second quarters, and seven wells are planned at Lashburn.

PRODUCTION

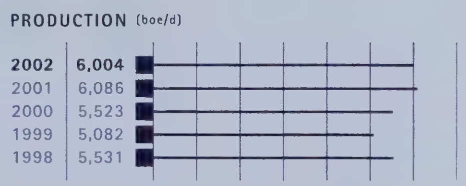
Freehold's production base is geographically widespread throughout western Canada, with the majority of properties located in Alberta. Production for the full year averaged 6,004 boe per day, relatively flat compared with 6,086 boe per day in 2001. Drilling on the Trust's royalty properties, combined with minor acquisitions, largely offset the normal decline. On a boe basis, approximately 70% of the Trust's production is derived from oil and natural gas liquids, and about half of this liquids production (37% of total production) is heavy oil.

In 2002, the Trust's production mix was 70% oil and NGLs, and 30% natural gas.



Average Daily Production	2002	2001	2000
Royalty lands			
Oil (bbls/d)	**2,657**	2,512	1,942
NGLs (bbls/d)	**211**	278	249
Natural gas (mmcf/d)	**7.7**	7.9	7.8
Oil equivalent (boe/d)	**4,153**	4,109	3,496
Working interest properties			
Oil (bbls/d)	**1,268**	1,360	1,411
NGLs (bbls/d)	**75**	77	78
Natural gas (mmcf/d)	**3.0**	3.2	3.2
Oil equivalent (boe/d)	**1,851**	1,977	2,027
Total Trust (boe/d)	**6,004**	6,086	5,523
Potash (tonnes/d)	**7.8**	7.9	10.9

Production volumes held steady in 2002, averaging 6,004 boe per day.



Production Reconciliation (boe/d)	Royalty Interest	Working Interest	Total Trust
Average daily production rate – 2001	4,109	1,977	6,086
Drilling on royalty lands	77	–	77
Development program	–	151	151
Acquisitions	13	–	13
Natural decline[1]	(46)	(277)	(323)
Average daily production rate – 2002	4,153	1,851	6,004

1 Includes timing of 2001 acquisitions and drilling.

MARKETING

Royalty Lands

The Trust's royalty lands consist of a large number of royalty properties and generally small volumes per property. A provision of the leases calls for Freehold's natural gas to be marketed with the lessees' production. Freehold has chosen to market its oil production in the same manner.

Working Interest Properties

Freehold markets most of its working interest oil production using 30-day contracts to ensure the highest competitive pricing and elects to market the majority of its natural gas production with the operators' gas.

HEDGING

While hedging may be used to attempt to equalize distributions, there is an opportunity cost in terms of distributable cash if the right hedging decisions are not made. Therefore, it has been Freehold's position to accept prices in the market and our production remains unhedged. This policy is subject to regular review by the Board of Directors.

PRICING

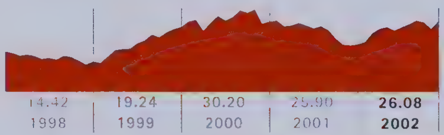
During 2002, West Texas Intermediate (WTI) crude oil prices ranged from a low of U.S. $21.62 in the first quarter to a high of U.S. $28.27 in the third quarter and averaged U.S. $26.08 per barrel for the year, relatively flat compared with the previous year. Improving fundamentals for heavy oil resulted in a narrowing of the price differential between light and heavy oil, as evidenced by 26% higher prices for Bow River heavy oil in 2002. The differential for 2002 narrowed to $8.27 per barrel compared with $14.11 in 2001. AECO natural gas prices were 35% lower in 2002.

Average Benchmark Commodity Prices[1]	**2002**	2001	2000
WTI crude oil (U.S. $/bbl)	**26.08**	25.90	30.20
Bow River heavy oil (Cdn. $/bbl)	**31.67**	25.07	34.35
AECO natural gas (Cdn. $/mcf)	**4.07**	6.30	5.02

1 Source: Canadian Association of Petroleum Producers.

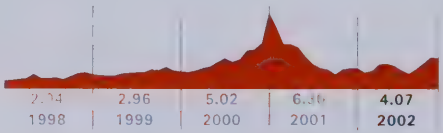
In 2002, WTI prices ranged from a low of U.S. $19.73 per barrel for the month of January to a high of U.S. $29.38 for December, averaging U.S. $26.08 per barrel for the year.

WTI CRUDE OIL PRICES (U.S. $/bbl)



In 2002, AECO prices ranged from a low of $2.77 per mcf for the month of August to a high of $5.66 for November, averaging $4.07 per mcf for the year.

AECO NATURAL GAS PRICES (Cdn. $/mcf)



As 37% of Freehold's total boe production is heavy oil, the improvement in the price differential between light and heavy oil throughout 2002 had a positive effect on realizations. Consequently, Freehold's average oil and natural gas liquids realization in 2002 was 24% higher than in 2001. The Trust's natural gas realizations averaged $3.81 per mcf, down 32% from the prior year.

Freehold Average Selling Prices	**2002**	2001	2000
Oil ($/bbl)	**31.25**	24.42	32.98
NGLs ($/bbl)	**25.09**	29.91	32.81
Oil and NGLs ($/bbl)	**30.83**	24.88	32.97
Natural gas ($/mcf)	**3.81**	5.64	4.71
Oil equivalent ($/boe)	**28.44**	27.63	31.39
Potash ($/tonne)	**143.33**	153.98	146.72

REVENUE

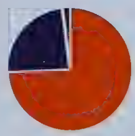
Gross revenue increased modestly to $63.1 million in 2002 from $61.9 million in 2001. The increase is a function of the 3% overall improvement in average selling prices, partially offset by a 1% decline in production volumes. The accompanying table demonstrates the net effect of price and volume variances on gross revenue.

Gross Revenue Variances ($000s)	**2002 vs. 2001**	2001 vs. 2000
Oil and NGLs		
Production (decrease) increase	(163)	4,881
Price increase (decrease)	9,170	(10,885)
Net increase (decrease)	9,007	(6,004)
Natural gas		
Production (decrease) increase	(568)	143
Price (decrease) increase	(7,487)	3,797
Net (decrease) increase	(8,055)	3,940
Other	306	(551)
Gross revenue increase (decrease)	1,258	(2,615)

In 2002, 75% of revenue came from oil and NGL production.

REVENUE BY PRODUCT (%)

Crude Oil & NGLs	75
Natural Gas	24
Potash	01



EXPENSES

Royalties Paid

Oil and gas producers pay royalties to the owners of mineral rights from whom they hold leases. These are paid to the Crown (provincial and federal government) and freehold mineral title owners. Royalties are directly related to prices and the level of oil and gas sales. As Freehold is the royalty owner on its royalty production, no royalties are paid to others on Freehold's share of production from the royalty lands. In 2002, royalties paid on production relating to ownership in working interest properties totalled $2.7 million, or 4% of gross revenue.

Royalty Expenses ($000s, except per boe)	2002	2001	2000
Royalty expense (net of ARC)	**2,709**	3,482	3,306
Per boe ($)	**1.24**	1.57	1.64
As a percentage of gross revenue	**4%**	6%	5%

Freehold does not incur operating expenses on its royalty production.

Operating Expenses

Freehold does not incur operating expenses on its royalty production. Operating expenses for the working interest properties rose 6% (13% per boe) in 2002. The major reasons for the increase were prior year adjustments in recorded production and the 6% decline in working interest production volumes. On a boe basis, operating costs for the total operations of the Trust (including the royalty lands) rose 8% year over year.

Operating Expenses ($000s, except per boe)	2002	2001	2000
Working interest properties	**4,679**	4,415	4,080
Per boe ($)	**6.93**	6.12	5.50
Royalty interest properties	**–**	–	–
Per boe ($)	**–**	–	–
Total operating expenses	**4,679**	4,415	4,080
Per boe ($)	**2.14**	1.99	2.02
As a percentage of gross revenue	**7%**	7%	6%

Freehold's combined operating costs, G&A costs and management fees (including acquisition fees) are among the lowest of the conventional oil and gas royalty trust group. In 2002, these combined expenses were $3.89 per boe compared with $3.57 per boe in 2001.

General and Administrative Expenses (G&A)

The Trust has a significant land administration and accounting requirement to administer and collect royalty payments relating to approximately 4,100 lease files and more than 15,000 producing wells. Net G&A expenses for 2002 rose 26% from 2001 (28% higher on a boe basis). The increase is primarily attributable to higher staffing levels as a result of significant acquisitions in 2001, which resulted in an increase in the allocation of overhead expenses to the Trust. Freehold also incurred additional legal fees and bank charges associated with the renegotiation of its existing bank financing commitment during 2002. The Manager of the Trust is reimbursed for overhead expenses incurred on behalf of Freehold.

G&A Expenses ($000s, except per boe)	2002	2001	2000
Gross G&A expenses	**2,967**	2,381	2,248
Less overhead recoveries[1]	**(144)**	(137)	(151)
Net G&A expenses	**2,823**	2,244	2,097
Per boe ($)	**1.29**	1.01	1.04
As a percentage of gross revenue	**4%**	4%	3%

1 As Freehold does not operate any of its royalty production, the Trust's overhead recoveries are minimal.

Management Fees

The Manager is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Fund (the pension fund for the employees of the Canadian National Railway Company). As part of the management agreement, the Manager receives a quarterly management fee paid in Trust Units. The Manager also earns an acquisition fee of 1.5% of the purchase price of oil and gas properties acquired by Freehold. This fee is charged to capital assets as part of the properties acquired.

During 2002, the Manager received 90,000 Trust Units as the management fee and $37,980 relating to acquisitions during the year. Since inception of the Trust in late 1996, the Manager has received total fees of $5.3 million, representing 2.8% of distributable income for the period.

The management agreement has a term of three years and is automatically renewed at the end of its term unless terminated one year prior to renewal. The management agreement will be renewed on November 26, 2004 unless terminated.

Freehold pays management fees in Trust Units. For the six-year life of the Trust, the Manager received a total of 504,236 Trust Units, with an ascribed value of $4.3 million.

Management Fees ($000s, except per boe)	**2002**	2001	2000
Management fees (paid in Trust Units)	**971**	776	625
Acquisition fees (1.5%)	**38**	483	76
Total fees	**1,009**	1,259	701
Per boe ($)	**0.46**	0.57	0.35
As a percentage of gross revenue	**2%**	2%	1%
As a percentage of distributable income	**3%**	3%	2%

NETBACKS

On the majority of its royalty production, Freehold does not pay royalties to others and does not incur capital expenditures, operating expenses, abandonment or site restoration expenses. The following netback analysis demonstrates the positive effect of this "royalty advantage."

2002 Netback Analysis ($ per boe)	Royalty Lands	Working Interest Properties	Total Trust
Gross revenue	$ 28.52	$ 29.47	$ 28.81
Royalty expense (net of ARC)	–	(4.01)	(1.24)
Net revenue	$ 28.52	$ 25.46	$ 27.57
Operating expense	–	(6.93)	(2.14)
Operating netback	$ 28.52	$ 18.53	$ 25.43
General and administrative expense	(1.29)	(1.29)	(1.29)
Interest expense	(0.26)	(0.98)	(0.48)
Capital taxes and other expenses	–	(0.39)	(0.12)
Funds generated from operations	$ 26.97	$ 15.87	$ 23.54
Site reclamation fund contributions	–	(0.36)	(0.11)
Provision for capital expenditures	–	(4.35)	(1.33)
Income available for distribution[1]	$ 26.97	$ 11.16	$ 22.10
Debt repayment	(1.37)	(1.37)	(1.37)
Acquisitions	(1.53)	–	(1.06)
Working capital changes	(1.63)	(1.63)	(1.63)
Investor netback	**$ 22.44**	**$ 8.16**	**$ 18.04**

1 Excludes management fee paid in Trust Units.

Royalties are received from gross production revenue – before deduction of Crown royalties and operating costs – and are not subject to capital expenditures or abandonment liabilities. This results in higher netbacks and therefore greater returns to our Unitholders.

INTEREST EXPENSE

Total interest expense declined 42% to $1.1 million during 2002, primarily due to lower prime borrowing rates and a net reduction in Freehold's long-term debt.

Interest Expense ($000s, except per boe)	**2002**	2001	2000
Interest on operating line	**16**	17	28
Interest on long-term debt	**1,044**	1,797	2,672
Net interest expense	**1,060**	1,814	2,700
Per boe ($)	**0.48**	0.81	1.34
As a percentage of gross revenue	**2%**	3%	4%

DEPLETION AND CEILING TEST

Oil and gas properties and royalty interests, including the costs of production equipment and future capital costs associated with proven reserves, are depleted on the unit-of-production method based on estimated proven oil and gas reserves before royalties payable. During 2002, the provision for depletion and depreciation was $21.1 million ($9.62 per boe), compared with $21.4 million ($9.64 per boe) in 2001.

In accordance with its stated accounting policies, Freehold applies a ceiling test to the carrying value of oil and gas assets, net of the provision for site restoration, plus future development costs to ensure that such costs do not exceed future estimated net revenues from production of proven reserves at year-end prices and costs. Future net revenues are calculated after deducting future general and administrative costs, financing costs, site restoration costs and applicable income taxes. No ceiling test write-down was required in 2002 or 2001.

RECLAMATION FUND

Freehold Royalty Trust and Freehold Resources Ltd. are liable for their share of ongoing environmental obligations and for the ultimate reclamation of the working interest properties upon abandonment. No similar responsibilities arise from the royalty lands. Ongoing environmental obligations are expected to be funded from cash flow. At December 31, 2002, the Trust's estimated share of future environmental and reclamation obligations for the working interest properties is approximately $5.6 million (2001 – $4.9 million).

A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. A total of $240,000 was paid into the reclamation account in 2002 (2001 – $240,000). During the period, $118,000 (2001 – $101,000) in site restoration expense was paid from the reclamation fund. The fund balance at year-end 2002 was $1.0 million.

TAXES

The Trust is a taxable trust under the Canadian Income Tax Act and it distributes substantially all of its taxable income to its Unitholders. The tax deductions received by the Trust for the distribution to Unitholders represent an exemption from taxation equivalent to the Trust's earnings. In addition, the Trust is exempt from future income taxes because it is contractually committed to distribute all of its income to its Unitholders.

Capital taxes consist primarily of Large Corporations Tax, which is incurred on taxable capital employed in Canada, and the Saskatchewan Capital Tax applied to both taxable capital and gross revenues in that province. Freehold Resources Ltd. (Resources) is a Canadian corporation subject to tax in various jurisdictions. Resources can deduct royalty payments to the Trust in determining taxable income, and is generally liable for income taxes on its 1% residual interest. Resources is subject to federal and capital tax in any jurisdiction (federal and provincial) in which it has a permanent establishment. In 2002, Resources had taxable income which gave rise to current taxes of $122,000 (2001 – $0).

Taxes ($000s)	**2002**	2001	2000
Large Corporations Tax	**48**	52	42
Saskatchewan Capital Tax	**95**	49	144
Current Income Tax	**122**	–	–
Total	**265**	101	186

UNITHOLDER TAXATION

Freehold is entitled to claim certain tax deductions available to all owners of oil and gas properties. By utilizing two principal deductions – the Canadian Oil and Gas Property Expense and the Resource Allowance deduction – cash distributions in the initial years were sheltered from income tax.

The Trust paid $1.31 per Trust Unit as cash distributions during 2002. For Canadian tax purposes, 58% of these distributions ($0.7598 per Trust Unit) were taxable to Unitholders as other income and 42% ($0.552 per Trust Unit) was tax deferred return of capital. The tax deferred return of capital will reduce the Unitholder's adjusted cost base for purposes of determining a capital gain or loss upon disposition of the Trust Units.

Over time, an increasing percentage of the annual distributions will become taxable. Based on current commodity prices, it is estimated that approximately 60% of distributable income will be taxable in 2003. The increase in taxability is the result of the depleting of tax pools.

Tax Pools[1] ($000s)	**2002**	2001	2000
Canadian oil and gas property expense	**171,205**	188,346	179,706
Canadian development expense	**4,913**	4,888	4,633
Canadian exploration expense	**–**	68	64
Capital cost allowance	**6,168**	6,778	8,130
Unit issue expenses	**806**	1,075	1,962
Non-capital loss carryovers	**–**	443	7,454
Total	**183,092**	201,598	201,949

1 Combined tax pools of Freehold Royalty Trust and Freehold Resources Ltd.

NET INCOME, CASH FLOW AND DISTRIBUTABLE INCOME

Net income increased 1% and funds generated from operations (cash flow) rose 4%, resulting in income available for distribution of $48.4 million in 2002, up 4% from 2001. After accounting for working capital changes of $3.6 million, debt repayments of $3.0 million and acquisition costs of $2.3 million, the Trust declared distributable income of $39.5 million, down 13% from 2001. Mineral title and gross overriding royalties lands accounted for 86% of the Trust's distributable income in 2002. The following reconciliation shows the deductions from gross revenue to arrive at distributable income.

2002 Distributable Income Analysis (000s)	Royalty Lands	Working Interest Properties	Total Trust
Gross revenue	43,241	19,902	63,143
Royalty expense (net of ARC)	–	(2,709)	(2,709)
Net revenue	43,241	17,193	60,434
Operating expense	–	(4,679)	(4,679)
Net operating income	43,241	12,514	55,755
General and administrative expense	(1,953)	(870)	(2,823)
Interest expense	(402)	(658)	(1,060)
Capital taxes and other expenses	–	(265)	(265)
Funds generated from operations	40,886	10,721	51,607
Site reclamation fund contributions	–	(240)	(240)
Provision for capital expenditures	–	(2,946)	(2,946)
Income available for distribution[1]	40,886	7,535	48,421
Debt repayment	(2,075)	(925)	(3,000)
Property and royalty acquisitions	(2,326)	–	(2,326)
Working capital changes	(2,466)	(1,099)	(3,565)
Distributable income	**34,019**	**5,511**	**39,530**
Percentage of distributable income	86%	14%	100%

1 Excludes management fee paid in Trust Units.

Payout Ratio ($000s)	**2002**	2001	2000
Funds generated from operations	**51,607**	49,829	51,943
Site reclamation fund contributions	**(240)**	(240)	(240)
Provision for capital expenditures	**(2,946)**	(2,992)	(5,161)
Income available for distribution[1]	**48,421**	46,597	46,542
Debt repayment	**(3,000)**	(4,594)	(3,638)
Acquisitions	**(2,326)**	0	(5,326)
Working capital changes	**(3,565)**	3,261	(2,352)
Distributable income	**39,530**	45,264	35,226
Payout ratio[2]	**77%**	91%	68%

1 Excludes management fee paid in Trust Units.
2 Distributable income as a percentage of funds generated from operations.

Since inception in late 1996, Freehold has paid out a total of 83% of funds generated from operations.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2002, Freehold's long-term debt totalled $30.0 million ($0.99 per Trust Unit), down from $33.0 million ($1.10 per Trust Unit) at the end of the previous year. Working capital at year-end totalled $7.9 million, resulting in net debt obligations of $22.1 million. Freehold's ratio of net debt to trailing cash flow of 0.4:1 demonstrates the Trust's solid financial condition. This balance sheet strength is a critical factor in Freehold's ability to pursue potential acquisition opportunities.

Debt Analysis ($000s)	**2002**	2001	2000
Long-term debt	**30,000**	33,000	38,000
Short-term debt (operating line)	**–**	–	–
Less: working capital	**7,920**	4,316	7,088
Net debt obligations	**22,080**	28,684	30,912

Financial Leverage and Coverage Ratios	**2002**	2001	2000
Ratio of net debt to cash flow	**0.4:1**	0.6:1	0.6:1
Distributable income to interest expense (times)	**37.0**	25.0	13.0
Net debt to distributable income (times)	**0.6**	0.6	0.9
Net debt to net debt plus equity (%)	**10.6**	12.7	14.4

ACQUISITIONS AND CAPITAL EXPENDITURES

Freehold acquired two royalty properties and completed one property swap for $2.3 million (net of adjustments) in the last half of 2002. These properties will contribute approximately 100 boe per day to Freehold's royalty production base in 2003.

Acquisition Summary ($000s)	**2002**	2001	2000
Purchase price	**2,532**	32,168	5,250
Acquisition fee (1.5%)	**38**	483	76
Interest expense	**–**	623	–
Evaluation and legal costs	**48**	145	–
Purchase price adjustments (net revenue from effective date to closing)	**(292)**	(3,712)	–
Net acquisition cost	**2,326**	29,707	5,326

As Freehold does not incur capital expenditures on its royalty lands, the Trust's operating capital requirements are relatively modest. On its working interest properties, the Trust incurred $2.9 million in capital expenditures in 2002 (2001 – $3.0 million). These expenditures were funded entirely from cash flow. For 2003, Freehold anticipates a capital budget of $4.6 million. The majority of this capital will be invested in development projects at Hayter and Pembina Cardium Unit No. 9 in Alberta, and at Lashburn, Saskatchewan.

The amount of capital expenditures deducted from income available for distribution is limited to 15% of annual net cash flow from operations.

Capital Expenditures ($000s)	**2002**	2001	2000
Development drilling	**1,824**	2,289	3,619
Plant and facilities	**1,122**	703	1,542
Total capital expenditures	**2,946**	2,992	5,161

BUSINESS RISKS AND MITIGATING STRATEGIES

The distributable income of an energy trust is subject to virtually the same industry risks and conditions faced by conventional oil and gas companies. The most significant of these include, but are not limited to, the following:

- Fluctuations in commodity prices and quality differentials as a result of weather patterns, world and North American market forces or shifts in the balance between supply and demand for crude oil and natural gas;
- Freehold's reserves will deplete over time through continued production and Freehold and its lessees may not be able to replace these reserves on an economic basis;
- Stock market volatility and the ability to access sufficient capital from internal and external sources;
- Variations in currency exchange rates;
- Industry activity levels and intense competition for land, goods and services and qualified personnel;
- Operational or marketing risks resulting in delivery interruptions, delays or unanticipated production declines;
- Imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves;
- Changes in government regulations and taxation; and
- Safety and environmental risks.

In addition, as a royalty trust, Freehold is subject to the following risks:

- As 30 royalty payors account for 90% of the Trust's royalty income, changes to their businesses may have a significant effect on Freehold's results;
- Potential Unitholder liability; and
- Higher prime borrowing rates, which may increase interest expense on the Trust's debt, and which may make fixed income investments more attractive to investors of Trust Units.

Freehold employs the following strategies to mitigate these risks:

- The Trust receives royalties on more than 15,000 producing oil and gas wells across western Canada. This diversified revenue stream limits the size of any one property with respect to total assets of the Trust;
- Freehold is not liable for abandonment and site reclamation costs on the royalty lands;
- Freehold adheres to strict investment criteria for acquisitions, seeking royalty and working interest properties that have high netbacks, long reserve life, low risk development potential and product diversification;
- Due to its high percentage of royalty lands, the Trust has the lowest all-in cost structure of its peer group. In addition, Freehold maintains a focus on controlling direct costs to maximize profitability;
- The Trust maintains an aggressive auditing program to ensure that the royalties paid are in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken. During 2002, Freehold's audit staff issued audit exception queries amounting to $3.0 million, bringing the total amount of audit exception queries since 1997 to $9.5 million, $7.7 million of which has been recovered;
- Freehold markets its products to a diverse range of buyers. Currently, Freehold does not have any commodity price, exchange rate or interest rate hedging programs in place and does not anticipate a change in that policy;

- Freehold employs a qualified team of oil and gas professionals with many years of experience and knowledge in managing the assets of the Trust;
- The possibility of any personal liability of Unitholders is very remote. The operations of the Trust are conducted in such a way as to avoid risk of liability on the Unitholders for claims against the Trust. All contracts contain provisions that exclude any liability of Unitholders and the Trust provides an indemnification to Unitholders;
- The Trust maintains levels of liability insurance that meet or exceed industry standards; and
- The Manager of the Trust employs a conservative approach to debt management. As circumstances warrant, Freehold allocates a portion of income available for distribution to debt repayment.

OUTLOOK AND SENSITIVITIES

As a result of strong investor interest, a number of new income trusts have entered the market in the last year. There are now about 200 royalty trusts and income funds listed on the Toronto Stock Exchange. This trend, which has increased competition for investment dollars, is expected to continue in the short-term, and may ultimately lead to consolidation within the Trust sector.

The high demand for natural gas production and reserves will likely continue to result in corporate and asset transactions as buyers strive to increase their natural gas assets and sellers take advantage of high transaction prices. This activity will undoubtedly provide opportunities for Freehold to acquire additional assets to sustain and grow the Trust. While our intention is to maintain a high proportion of royalty income, we will consider acquiring working interest properties – or even corporate acquisitions – if they meet our investment criteria.

While current world events have caused commodity prices to spike, we anticipate some weakening in oil prices toward the last half of 2003. The price outlook for heavy oil is positive as a result of a return to supply/demand balance. We believe that natural gas, as a North American commodity, has greater stability in terms of short-term pricing.

Assuming average prices of Cdn. $5.00 per mcf for natural gas, U.S. $25.00 per barrel for WTI crude oil with a light/heavy oil price differential of Cdn. $8.00 per barrel and a production forecast of 5,800 boe per day, Freehold estimates that approximately $1.40 per Trust Unit will be distributed to Unitholders in 2003.

However, oil and gas price fluctuations, interest rate changes, Cdn./U.S. dollar exchange rates, levels of production and light/heavy oil price differentials can all influence distributable income of the Trust. The following table provides an analysis of the potential impact these key factors may have on distributable income in 2003.

Sensitivity Analysis[1]

		Estimated Change in Distributable Income	
Variables	Change (+/–)	($000s)	Per Trust Unit ($)
WTI crude oil price	U.S. $1.00/bbl	2,420	0.08
Light/heavy oil price differential	Cdn. $1.00/bbl	1,514	0.05
Natural gas price	Cdn. $0.25/mcf	909	0.03
Cdn./U.S. dollar exchange rate	$0.01	909	0.03
Interest rates	1%	303	0.01
Oil and NGLs production	100 bbls/d	1,212	0.04
Natural gas production	1,000 mcf/d	1,818	0.06

1 Based on 2003 budget forecast.

ENGINEERS' REPORT

To the Unitholders of Freehold Royalty Trust

This letter is to confirm that Trimble Engineering Associates Ltd. ("Trimble") was retained as an independent consultant to evaluate the petroleum and natural gas reserves of Freehold Royalty Trust.

Trimble has prepared a report dated January 31, 2003, entitled "Reserve and Present Worth Appraisal of Certain Oil & Gas Properties at January 1, 2003," which represents the results of this evaluation. The report has been prepared in accordance with the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. Examinations were made in accordance with generally accepted engineering standards and included such tests and other procedures as were considered necessary.

The accuracy of reserves evaluated and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. The estimates presented were considered reasonable at the time this report was prepared. However, they should be accepted with the understanding that reservoir performance subsequent to the date of the estimates may necessitate revision.

In our opinion, our report presents fairly, in all material respects, the estimated production and resulting cash flows and net present values of Freehold Royalty Trust's reserves, as at January 1, 2003.

Trimble Engineering Associates Ltd.
Calgary, Canada
February 20, 2003

RESERVES

Freehold's reserves were independently evaluated by Trimble Engineering Associates Ltd. effective January 1, 2003. Freehold's Audit Committee met with the reserve evaluators to review their findings and procedures. Year-over-year, established reserves (proven plus half probable) declined 5% to 26.8 million boe (0.887 boe per Trust Unit), as reserves added through acquisitions and development activities did not offset annual production.

Freehold replaced 55% (2001 – 175%) of its annual production through acquisitions and development activities (excluding revisions of prior estimates). The average cost of reserve replacement was $4.40 per boe in 2002, compared with $8.40 per boe in 2001. This low cost reserve replacement is influenced by the drilling on Freehold's royalty lands where Freehold pays no capital.

Including the potash reserves (evaluated by the Manager at $4.9 million), the present value of Freehold's future net revenue, discounted at 12%, totalled $254 million. This represents a 14% increase over the prior year due to the application of a higher price forecast at year-end 2002.

Reserve Life Index (RLI) is calculated by dividing the year-end remaining reserves by the annual production in that year. This provides a simplified representation of the number of years of reserves remaining if production remained constant at that rate. The actual productive life of the reserves is significantly longer due to a declining production rate over time. Based on established reserves of 26.8 million boe and annual production of 2.2 million boe in 2002, Freehold's RLI is 12.2 years. This compares with an RLI of 12.7 years at December 31, 2001.

Revisions to prior reserve estimates were minor. The adjustments were both positive and negative and occurred on a large number of properties.

	2002		2001		2000	
Summary of Reserves	**Proven**	**Established[1]**	Proven	Established[1]	Proven	Established[1]
Oil (mbbls)	**13,365**	**16,373**	13,744	16,732	12,809	15,842
NGLs (mbbls)	**2,129**	**2,353**	2,136	2,421	2,255	2,533
Natural gas (mmcf)	**40,607**	**48,522**	44,335	54,146	50,746	58,651
Total (mboe)	**22,262**	**26,813**	23,269	28,177	23,522	28,150
Reserve life index (years)[2]	**10.2**	**12.2**	10.5	12.7	11.7	14.0
Potash (mtonnes)	**63,162**	**63,162**	65,972	65,972	68,857	68,857

1 Proven plus half probable.
2 Excludes potash reserves.

Reserves Reconciliation	Oil and NGLs (mbbls)		Natural Gas (mmcf)		Combined Equivalent (mboe)		
	Proven	Probable[1]	Proven	Probable[1]	Proven	Probable[1]	Established
Balance, Jan. 1, 2002	15,880	3,273	44,335	9,811	23,269	4,909	28,177
Reserve additions	269	437	1,508	47	520	444	965
Acquisitions	211	15	40	9	218	17	234
Revisions	722	(478)	(864)	(1,946)	578	(803)	(225)
Dispositions	(50)	(14)	(490)	(6)	(131)	(15)	(147)
Production	(1,538)	–	(3,922)	–	(2,191)	–	(2,191)
Balance, Jan. 1, 2003	15,494	3,232	40,607	7,915	22,262	4,552	26,813
Change over prior year	(386)	(41)	(3,728)	(1,896)	(1,007)	(357)	(1,364)

1 Probable reserves are risked at 50%.

Present Value of Estimated Future Net Revenue ($000s)	Discounted at 0%	10%	12%	15%
Proven producing	584,529	239,558	218,799	194,827
Proven non-producing	13,249	7,496	6,860	6,066
Total proven	597,778	247,054	225,659	200,893
Probable[1]	127,161	25,893	21,912	17,639
Established reserves	724,939	272,947	247,571	218,532
Potash	20,512	5,633	4,890	4,101
Alberta Royalty Credit	3,831	2,057	1,903	1,716
Total	**749,282**	**280,637**	**254,364**	**224,349**

1 Probable reserves are risked at 50%.

Price Forecast	Oil[1]		Natural Gas[1]	Natural Gas Liquids[1]			Potash[2]	Currency[1]
	WTI[3]	Edmonton Par Price 40° API	Alberta Plant Gate	Propane	Butane	Pentane	Potash	Exchange Rate U.S./Cdn. Dollar
	$U.S./bbl	$/bbl	$/mmbtu	$/bbl	$/bbl	$/bbl	$/tonne	
2003	25.99	38.43	5.72	21.53	24.35	39.36	132.88	0.63
2004	23.60	34.82	5.21	19.50	22.06	35.66	134.87	0.63
2005	21.63	32.22	4.60	18.05	20.42	33.00	136.90	0.62
2006	21.96	32.78	4.27	18.36	20.77	33.57	138.95	0.62
2007	22.29	33.90	4.42	18.99	21.48	34.72	141.03	0.61
Per year, thereafter	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	0.60

1 January 1, 2003 price forecast by Sproule Associates Limited.
2 Potash price forecast prepared by Rife Resources Ltd.
3 40° API, 0.4% sulphur at Cushing, Oklahoma.

Replacement and Recycle Statistics ($000s, except boe)	Three-year results	2002	2001	2000
Development expenditures	**11,099**	**2,946**	2,992	5,161
Established reserve additions (mboe)	**3,898**	**965**	1,359	1,574
Development cost ($/boe)	**2.85**	**3.05**	2.20	3.28
Acquisition expenditures	**37,359**	**2,326**	29,707	5,326
Established reserve additions (mboe)	**3,359**	**234**	2,535	590
Acquisition cost ($/boe)	**11.12**	**9.94**	11.72	9.03
Total development and acquisition expenditures	**48,458**	**5,272**	32,699	10,487
Established reserve additions (mboe)	**7,257**	**1,199**	3,894	2,164
Development and acquisition cost ($/boe)	**6.68**	**4.40**	8.40	4.85
Established reserve additions including revisions (mboe)	**4,181**	**827**	2,249	1,105
Development and acquisition costs including revisions ($/boe)[1]	**11.59**	**6.37**	14.54	9.49
Operating netback per boe[2]	**25.93**	**25.43**	24.30	28.26
Recycle ratio[3]	**2.2**	**4.0**	1.7	3.0

1 Development and acquisition costs, including revisions, represent the average cost of acquiring and developing established reserves (also referred to as finding and development (F & D) costs).
2 The operating netback per boe is calculated as total revenue, less operating costs and royalties net of ARC.
3 The recycle ratio is a key measure of the efficiency in which new reserves are added. It is calculated as the operating netback divided by the average cost of acquiring and developing new reserves (including revisions).

NET ASSET VALUE

Net asset value is an estimate of the underlying value of Freehold's reserves and undeveloped land, prior to provision for income taxes, interest expense, general and administrative costs and management fees, but taking into consideration estimated royalties, operating costs, other income, capital costs and abandonment costs.

Future net revenue estimates are greatly influenced by price forecasts and future reservoir performance.

Based on the independent evaluation of the Trust's established reserves, the Trust's net asset value at December 31, 2002 was $7.87 per Trust Unit (discounted at 12%), up 19% from $6.64 a year ago. The increase is related to higher reserve values resulting from a higher price forecast, increased working capital and lower bank debt at year-end 2002.

Net Asset Value as at December 31, 2002		Discounted at	
($000s, except unit data)	10%	12%	15%
Present value of established oil and natural gas reserves[1]	275,004	249,474	220,248
Present value of potash reserves[2]	5,633	4,890	4,101
Undeveloped land[3]	4,554	4,554	4,554
Reclamation fund	1,006	1,006	1,006
Working capital	7,920	7,920	7,920
Bank debt	(30,000)	(30,000)	(30,000)
Net asset value	264,117	237,844	207,829
Trust Units outstanding	30,225,236	30,225,236	30,225,236
Net asset value per Trust Unit	8.74	7.87	6.88

1 Evaluated by Trimble Engineering Associates Ltd. and includes ARC.
2 Evaluated by Rife Resources Ltd.
3 Evaluated by Seaton-Jordan & Associates Ltd.

Management has prepared the accompanying combined financial statements of Freehold Royalty Trust in accordance with Canadian generally accepted accounting principles.

Management is responsible for the accuracy and integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and reliable accounting records are produced for financial reporting purposes.

External auditors, KPMG LLP, were appointed by the Trust's Unitholders to perform an examination of the corporate and accounting records so as to express an opinion on the combined financial statements of Freehold Royalty Trust. Their examination included a review and evaluation of Freehold's internal control systems and included tests and procedures considered necessary to provide reasonable assurance that the combined financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the Audit Committee, all of whose members are independent directors of Freehold Resources Ltd. The Committee meets with management and the independent auditors to ensure that management's responsibilities are properly discharged.

D J Sandmeyer

David J. Sandmeyer
PRESIDENT & CHIEF EXECUTIVE OFFICER

J.N. Holowisky

Joseph N. Holowisky
VICE-PRESIDENT, FINANCE & ADMINISTRATION & CHIEF FINANCIAL OFFICER AND SECRETARY

February 20, 2003

AUDITORS' REPORT

To the Unitholders of Freehold Royalty Trust

We have audited the combined balance sheets of Freehold Royalty Trust as at December 31, 2002 and 2001 and the combined statements of income, Unitholders' equity and cash flows for the years ended December 31, 2002 and 2001. These combined financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these combined financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these combined financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years ended December 31, 2002 and 2001 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KPMG LLP
CHARTERED ACCOUNTANTS
Calgary, Canada
February 20, 2003

	December 31	
($000s)	**2002**	2001
Assets		
Current assets:		
Cash	**$ 316**	$ 260
Accounts receivable	**13,443**	9,074
	13,759	9,334
Reclamation fund (note 6)	**1,006**	884
Petroleum and natural gas interests, net of accumulated depletion and depreciation of $132,399 (2001 – $111,316)	**209,557**	225,367
	$ 224,322	$ 235,585
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	**$ 3,020**	$ 3,013
Accounts payable and accrued liabilities	**2,819**	2,005
	5,839	5,018
Provision for future site restoration (note 6)	**1,353**	1,125
Long-term debt (note 2)	**30,000**	33,000
Future income tax liability (note 8)	**1,650**	–
Unitholders' equity (note 3)	**185,480**	196,442
	$ 224,322	$ 235,585

See accompanying notes to combined financial statements.

Approved on behalf of Freehold Royalty Trust by Freehold Resources Ltd., as Administrator:

William W. Siebens
DIRECTOR

D. Nolan Blades
DIRECTOR

COMBINED STATEMENTS OF INCOME

($000s, except per unit data)	Years Ended December 31 2002	2001
Revenue:		
Royalty income and working interest sales	**$ 63,143**	$ 61,885
Royalty expense (net of ARC)	**(2,709)**	(3,482)
	60,434	58,403
Other expenses:		
Operating	**4,679**	4,415
General and administrative	**2,823**	2,244
Interest on long-term debt	**1,044**	1,797
Other interest	**16**	17
Capital taxes and other	**265**	101
	8,827	8,574
Funds generated from operations	**51,607**	49,829
Depletion and depreciation	**21,083**	21,402
Provision for future site restoration	**346**	352
Management fee (note 5)	**971**	776
Net income before income taxes	**29,207**	27,299
Future income tax provision (note 8)	**1,650**	–
Net income	**$ 27,557**	$ 27,299
Net income per Trust Unit, basic and diluted	**$ 0.91**	$ 0.95

See accompanying notes to combined financial statements.

COMBINED STATEMENTS OF UNITHOLDERS' EQUITY

($000s)	December 31 2002	2001
Unitholders' equity, beginning of year	**$ 196,442**	$ 183,029
Net income	**27,557**	27,299
Distributions to Unitholders	**(39,530)**	(45,264)
Issue of new Trust Units	**1,011**	31,378
Unitholders' equity, end of year	**$ 185,480**	$ 196,442

See accompanying notes to combined financial statements.

	Years Ended December 31	
($000s)	**2002**	2001
Cash provided by (used in):		
Operating:		
Net income	**$ 27,557**	$ 27,299
Items not involving cash:		
Depletion and depreciation	**21,083**	21,402
Future income tax provision	**1,650**	–
Provision for future site restoration	**346**	352
Trust Units issued in lieu of management fee	**971**	776
Funds generated from operations	**51,607**	49,829
Changes in non-cash working capital (note 9)	**(3,555)**	2,412
	48,052	52,241
Financing:		
Issue of new Trust Units	**–**	31,845
Issue cost of new Trust Units	**–**	(1,343)
Trust Units issued upon exercise of options	**40**	100
Long-term debt	**(3,000)**	(5,000)
Distributions paid	**(39,524)**	(44,924)
	(42,484)	(19,322)
Investing:		
Property and royalty acquisitions (note 5)	**(2,326)**	(29,707)
Development expenditures	**(2,946)**	(2,992)
Site reclamation fund contributions	**(240)**	(240)
	(5,512)	(32,939)
Increase (decrease) in cash	**56**	(20)
Cash, beginning of year	**260**	280
Cash, end of year	**$ 316**	$ 260

Cash interest paid during 2002 was $1,071 (2001 – $1,686).
See accompanying notes to combined financial statements.

Years ended December 31, 2002 and 2001.

BASIS OF PRESENTATION

Freehold Royalty Trust ("the Trust") is an open-end investment trust formed under the laws of the Province of Alberta pursuant to a trust indenture dated September 30, 1996 as amended from time to time. The Trust holds royalty interests directly and a 99% royalty interest in the funds generated by Freehold Resources Ltd. ("Resources").

Resources was incorporated on June 3, 1996 and derives its income from certain oil and gas working interest properties.

These combined financial statements include the accounts of the Trust and Resources. All inter-entity transactions have been eliminated.

1. SIGNIFICANT ACCOUNTING POLICIES

(a) Property, plant and equipment:

The Trust follows the full cost method of accounting.

All costs of acquiring, exploring for and developing oil and gas and related reserves are capitalized. Such costs include land acquisition, geological and geophysical, carrying charges of unproved properties, costs of drilling both productive and non-productive wells and directly related general and administrative costs. Costs are reduced by proceeds from the sale of oil and gas properties and by government grants. Gains and losses are not recognized upon disposition of oil and gas properties unless such a disposition would alter the rate of depletion by 20% or more.

(b) Ceiling test:

The Trust applies a ceiling test to the carrying value of oil and gas assets, net of the provision for site restoration, plus future development costs to ensure that such costs do not exceed future estimated net revenues from production of proven reserves at year-end prices and costs. Future revenues are calculated after deducting future general and administrative costs, financing costs, site restoration costs and Resources' income taxes.

(c) Depletion:

Oil and gas properties and royalty interests, including the costs of production equipment and future capital costs associated with proven reserves, are depleted on the unit-of-production method based on estimated proven oil and gas reserves before royalties. Reserves are converted to equivalent units on the basis of relative energy content.

(d) Provision for future site restoration:

Estimated future site restoration costs are provided for using the unit-of-production method. Costs are estimated by the Trust based on current regulations, costs, technology and industry standards. Actual site restoration costs are charged to the accumulated provision account as incurred.

(e) Income and other taxes:

The Trust is a taxable trust under the Income Tax Act (Canada) and it distributes substantially all of its taxable income to its Unitholders. The tax deductions received by the Trust for the distributions to Unitholders represent an exemption from taxation equivalent to the Trust's earnings. In addition, the Trust is exempt from future income taxes because it is contractually committed to distribute all of its income to its Unitholders.

Resources follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. Resources can deduct royalty payments to the Trust in determining taxable income and is generally liable for income taxes on its 1% residual interest.

(f) Cash:
Cash includes cash on deposit and highly liquid investments with original maturities of three months or less.

(g) Measurement uncertainty:
The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses during the reporting period. Actual results could differ as a result of using estimates.

(h) Stock based compensation plans:
In accordance with the Trust's Unit Option Plan, Trust Units are granted to the independent directors of Resources and to the Manager, Rife Resources Management Ltd. The Trust does not recognize compensation expense on the issuance of Trust Unit options under this plan, as the exercise price of the Trust Unit options is equal to the market value of Trust Units on the day they are granted.

Effective January 1, 2002, new accounting standards were adopted for stock-based compensation and other stock-based payments. The new standards require additional disclosure for options granted to employees, officers and directors and that a compensation cost be recorded for the fair value of options granted to non-employees. There was no significant impact on the financial statements upon adoption of this standard, however grants of options to the Manager and any other non-employees subsequent to January 1, 2002 will result in a compensation cost charged to income.

(i) Earnings per unit:
Basic units outstanding are the weighted average number of units outstanding for each period. Diluted units outstanding are calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back units at the average market price for the period.

2. LONG-TERM DEBT

The Trust has a $50.0 million committed production facility on which $30.0 million was drawn at December 31, 2002 (2001 — $33.0 million). The facility is secured by a General Security Agreement from the Trust and Resources providing a first priority security interest in both Resources' and the Trust's assets and specific assignment of royalties. A demand debenture is pledged from both Resources and the Trust in the amount of $100.0 million, conveying a first floating charge over all property. The facility is structured as a one year committed revolving credit facility, extendible annually. In the event that the lender does not consent to such extension, the revolving credit facility will convert to a three year non-revolving amortizing term loan with principal payments due quarterly. At December 31, 2002 and 2001, the entire amount outstanding under the production facility is presented as long-term based on the Trust's ability to refinance any current amount with the undrawn portion of the facility.

In addition, the Trust has available a $15.0 million demand operating facility and a U.S. $10.0 million swap facility, of which, nil was drawn down as at December 31, 2002 and 2001. The facilities have security similar to that of the production facility with any amounts outstanding payable on demand.

Borrowings under the facility bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 90 to 165 basis points.

3. UNITHOLDERS' EQUITY

The Trust has authorized an unlimited number of Trust Units of which 30,225,236 (2001 – 30,129,236) were issued at December 31, 2002.

	2002		2001	
	Number	**Amount**	Number	Amount
Trust Units Issued		**($000s)**		($000s)
Balance, beginning of year	**30,129,236**	**$ 284,761**	26,728,000	$ 253,383
Issued for cash	**–**	**–**	3,300,000	31,845
Less: issue costs	**–**	**–**	–	(1,343)
Issued upon exercise of options	**6,000**	**40**	15,000	100
Issued in lieu of management fee	**90,000**	**971**	86,236	776
Balance, end of year	**30,225,236**	**$ 285,772**	30,129,236	$ 284,761

The Trust has reserved 1,980,000 Trust Units pursuant to a Trust Unit Option Plan. Options to purchase Trust Units may be issued to the independent directors of Resources or the Manager.

As at December 31, 2002, options to purchase 1,139,000 (2001 – 1,145,000) Trust Units were outstanding and fully vested (2001 – 15,000 vested). 1,130,000 of the options are priced at $9.24 and expire November 14, 2006. During 2002, 6,000 of the $6.65 options were exercised with 9,000 remaining and expiring August 12, 2003.

The Trust has reserved 500,000 Trust Units pursuant to its management agreement with the Manager, of which 84,236 have been issued to date (see note 5).

The weighted average number of Trust Units outstanding for 2002 was 30,165,167 (2001 – 28,839,216).

4. DISTRIBUTIONS

Distributable income is paid on a monthly basis, with payments to be made on the 15th day following the month-end.

5. RELATED PARTY TRANSACTIONS

The Manager provides certain services for a fee based on a specified number of Trust Units per quarter, pursuant to a management agreement which has a term of three years and will be renewed on November 26, 2004 unless terminated. During 2002, the management fee charged was 90,000 Trust Units with an ascribed value of $971,000 (2001 – 86,236 Trust Units with an ascribed value of $776,000).

During the year, the Manager charged the Trust $2,035,000 (2001 – $1,759,000) in general and administrative costs. At December 31, 2002, there was $148,000 (2001 – $287,000) included in accounts payable relating to these costs.

The Manager also earns a fee of 1.5% of the purchase price of oil and gas properties acquired by Freehold. During 2002, the Manager acquired $2,532,000 ($2,326,000 net) of properties on behalf of the Trust (2001 – $32,168,000, net $29,707,000) and was paid $37,980 (2001 – $483,000) relating to these acquisitions. This fee is charged to capital assets as part of the properties acquired.

6. FUTURE SITE RESTORATION AND RECLAMATION COST

The Trust and Resources are liable for their share of ongoing environmental obligations and for the ultimate reclamation of the working interest properties upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow. The total estimated future environmental and reclamation obligations in respect of the working interest properties are approximately $5,622,000 (2001 – $4,926,000). A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. During the period, $118,000 (2001 – $101,000) in site restoration was incurred and paid from the reclamation fund.

The costs of unproved lands at December 31, 2002, of $4.2 million have been excluded from the depletion calculation.

7. DISTRIBUTABLE INCOME

	Years Ended December 31	
($000s, except per unit data)	**2002**	2001
Funds generated from operations	**$ 51,607**	$ 49,829
Deduct:		
Site reclamation fund contributions	**(240)**	(240)
Provision for capital expenditures[1]	**(2,946)**	(2,992)
Income available for distribution	**$ 48,421**	$ 46,597
Per Trust Unit	**$ 1.61**	$ 1.62
Debt repayment	**(3,000)**	(4,594)
Property and royalty acquisitions	**(2,326)**	–
Working capital change	**(3,565)**	3,261
Distributable income	**$ 39,530**	$ 45,264
Per Trust Unit	**$ 1.31**	$ 1.56

1 The amount of capital expenditures is limited to 15% of annual net cash flow from operations, unless additional capital expenditures are financed with borrowings, additional issuances of Trust Units or proceeds from the disposition of assets.

8. INCOME TAXES

Resources uses the liability method of accounting for income taxes, as described in note 1. The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to the Trust's earnings before income taxes. This difference results from the following items:

($000s)	**2002**	2001
Earnings before income taxes and capital taxes	**$ 29,472**	$ 27,400
Combined federal and provincial tax rate	**42.6%**	42.6%
Computed "expected" income tax expense	**$ 12,537**	$ 11,672
Increase (decrease) in income tax resulting from:		
Non-taxable earnings of the Trust	**(10,153)**	(11,285)
Non-deductible Crown charges	**9**	13
Resource allowance	**(547)**	(359)
Changes in enacted tax rates	**–**	27
Other	**(3)**	(4)
Future income tax expense	**1,843**	64
Change in valuation allowance	**(193)**	(64)
Income taxes	**$ 1,650**	$ –
Capital taxes[1]	**$ 143**	$ 101

1 In 2002, Resources made cash payments of $150,000 in taxes (2001 – $154,000).

The components of Resources' future income taxes at December 31 are as follows:

($000s)	**2002**	2001
Future income tax liabilities:		
Oil and natural gas properties	**$ 2,080**	$ 355
Future income tax assets:		
Abandonment costs	**(430)**	(359)
Loss carryforwards	**–**	(189)
Valuation allowance	**–**	193
Future income taxes	**$ 1,650**	$ –

9. SUPPLEMENTAL CASH FLOW DISCLOSURE

Changes in Non-Cash Working Capital Balance ($000s)	**2002**	2001
Accounts receivable	**$ (4,369)**	$ 3,187
Accounts payable and accrued liabilities	**814**	(775)
	$ (3,555)	$ 2,412

Financial ($000s, except unit data)	2002	2001	2000	1999	1998
Gross revenue	**63,143**	61,885	64,500	36,355	24,839
Operating expenses	**4,679**	4,415	4,080	3,555	3,655
General and administrative expenses	**2,823**	2,244	2,097	1,882	2,248
Interest expense	**1,060**	1,814	2,700	2,410	2,478
Depletion and depreciation	**21,083**	21,402	19,257	17,926	23,670
Capital expenditures	**2,946**	2,992	5,161	940	1,790
Property acquisitions	**2,326**	29,707	5,326	–	–
Distributable income	**39,530**	45,264	35,226	20,757	17,186
Per Trust Unit ($)	**1.31**	1.56	1.32	0.78	0.65
Long-term debt	**30,000**	33,000	38,000	39,288	39,288
Unitholders' equity	**185,480**	196,442	183,029	185,938	197,474
Trust Units outstanding end of year	**30,225,236**	30,129,236	26,728,000	26,648,000	26,568,000
Weighted average	**30,165,167**	28,839,216	26,678,328	26,598,411	26,518,411

Operating					
Production					
Oil and NGLs (bbls/d)	**4,214**	4,227	3,680	3,223	3,547
Natural gas (mmcf/d)	**10.7**	11.2	11.0	11.2	11.9
Oil equivalent (boe/d)	**6,004**	6,086	5,523	5,082	5,531
Potash (tonnes/d)	**7.8**	7.9	10.9	14.2	15.3
Average sales price					
Oil and NGLs ($/bbl)	**30.83**	24.88	32.97	21.37	13.00
Natural gas ($/mcf)	**3.81**	5.64	4.71	2.48	1.91
Oil equivalent ($/boe)	**28.44**	27.63	31.39	18.99	12.45
Potash ($/tonne)	**143.33**	153.98	146.72	157.56	147.72
Undeveloped land (gross acres)	**235,062**	237,443	140,896	136,036	132,609
Established reserves (mboe)	**26,813**	28,177	28,150	29,062	29,952
Reserve life index (years)	**12.2**	12.7	14.0	15.7	14.8

Trading Activity					
High ($)	**11.35**	10.10	9.50	6.90	9.80
Low ($)	**9.00**	8.00	5.60	4.13	4.15
Close ($)	**10.88**	9.20	8.70	5.95	4.43
Volume (000s)	**7,323**	8,162	6,752	5,782	9,686

2002

Financial ($000s, except unit data)	Q1	Q2	Q3	Q4
Gross revenue	12,844	16,235	16,503	17,561
Operating expenses	1,038	1,296	1,216	1,129
General and administrative expenses	911	690	587	635
Distributable income	7,231	9,653	11,169	11,477
Per Trust Unit ($)	0.24	0.32	0.37	0.38
Long-term debt	33,000	30,500	30,500	30,000
Unitholders' equity	193,790	192,296	189,394	185,480
Trust Units outstanding end of quarter	30,135,000	30,180,236	30,202,736	30,225,236
Weighted average	30,129,300	30,146,927	30,180,481	30,202,981

Operating				
Production				
Oil and NGLs (bbls/d)	4,311	4,065	4,172	4,303
Natural gas (mmcf/d)	10.4	11.7	10.5	10.4
Oil equivalent (boe/d)	6,046	6,015	5,922	6,033
Average sales price				
Oil and NGLs ($/bbl)	25.24	32.39	34.03	31.74
Natural gas ($/mcf)	3.11	3.80	3.29	5.02
Oil equivalent ($/boe)	23.35	29.27	29.81	31.27

Trading Activity				
High ($)	10.35	10.95	11.35	11.33
Low ($)	9.00	9.58	9.50	10.00
Close ($)	10.25	10.85	11.17	10.88
Volume (000s)	1,829	1,572	2,428	1,494

2001

Financial ($000s, except unit data)	Q1	Q2	Q3	Q4
Gross revenue	19,001	16,018	16,086	10,780
Operating expenses	1,089	975	1,184	1,167
General and administrative expenses	614	534	508	588
Distributable income	10,693	13,199	12,337	9,034
Per Trust Unit ($)	0.40	0.45	0.41	0.30
Long-term debt	38,000	31,000	31,000	33,000
Unitholders' equity	182,868	207,879	202,839	196,442
Trust Units outstanding				
end of quarter	26,748,000	30,084,236	30,106,736	30,129,236
Weighted average	26,728,222	28,386,365	30,084,481	30,106,981

Operating				
Production				
Oil and NGLs (bbls/d)	3,827	4,149	4,541	4,381
Natural gas (mmcf/d)	11.3	11.4	10.9	11.0
Oil equivalent (boe/d)	5,709	6,050	6,359	6,219
Average sales price				
Oil and NGLs ($/bbl)	24.88	25.16	30.74	18.55
Natural gas ($/mcf)	10.12	6.15	3.09	3.17
Oil equivalent ($/boe)	36.70	28.84	27.26	18.69

Trading Activity				
High ($)	10.00	10.10	9.64	9.58
Low ($)	8.35	8.50	8.00	8.11
Close ($)	8.90	9.00	8.90	9.20
Volume (000s)	1,430	2,801	2,098	1,834

2002 TAX INFORMATION

Freehold Royalty Trust's cash distributions became taxable in the 2001 taxation year. Distributions paid in 2002 were 58% taxable (other income) and 42% tax deferred (return of capital).

Record Date	Payment Date	Taxable Amount (Box 26 Other Income)	Tax Deferred Amount (Return of Capital)	Total Cash Distribution
December 31, 2001	January 15, 2002	$ 0.0580	$ 0.0420	$ 0.10
January 31, 2002	February 15, 2002	0.0464	0.0336	0.08
February 28, 2002	March 15, 2002	0.0464	0.0336	0.08
March 31, 2002	April 15, 2002	0.0464	0.0336	0.08
April 30, 2002	May 15, 2002	0.0464	0.0336	0.08
May 31, 2002	June 15, 2002	0.0812	0.0588	0.14
June 30, 2002	July 15, 2002	0.0580	0.0420	0.10
July 31, 2002	August 15, 2002	0.0580	0.0420	0.10
August 31, 2002	September 15, 2002	0.0986	0.0714	0.17
September 30, 2002	October 15, 2002	0.0580	0.0420	0.10
October 31, 2002	November 15, 2002	0.0580	0.0420	0.10
November 30, 2002	December 15, 2002	0.1044	0.0756	0.18
Total paid during the 2002 Taxation Year		$ 0.7598	$ 0.5502	$ 1.31

HISTORICAL TAX INFORMATION

Payment Period[1]	Taxable Amount Per Unit[2]	Tax Deferred Amount Per Unit[3]	Taxable Percentage	Tax Deferred Percentage	Total Cash Distribution for Tax Purposes Per Unit
2002	**$ 0.7598**	**$ 0.5502**	**58%**	**42%**	**$1.31**
2001	0.5928	0.9672	38%	62%	1.56
2000	0.0000	1.2900	0%	100%	1.29
1999	0.0000	0.7600	0%	100%	0.76
1998	0.0000	0.8500	0%	100%	0.85
1997	0.0000	0.9800	0%	100%	0.98

1 For income tax purposes, only cash payments received in each calendar year are subject to Canadian income tax. This results in the December distribution, which is paid to Unitholders on January 15, being taxed in the following year.

2 As at December 31, 2002, the Trust has the benefit of $183 million of income tax pools to reduce the taxable portion of future distributions.

3 The tax deferred amount reduces the adjusted cost base of a Unitholder's investment in the Trust. A more detailed list of historical distributions (showing record dates, payment dates and tax treatment) can be obtained from Freehold's Website, www.freeholdtrust.com, or by contacting Freehold directly.

ADJUSTED COST BASE FOR CAPITAL GAINS PURPOSES

The Adjusted Cost Base ("ACB") of the Trust Units is required in calculating a capital gain or loss upon the disposition of Trust Units if the owner holds the Trust Units as capital property. The ACB is the original cost of the Trust Unit paid by the Unitholder (including purchase commissions), less any tax deferred (return of capital) distributions received by the Unitholder. Unitholders should maintain a record of all distributions that are classified as partially or entirely a return of capital distribution while holding Freehold Royalty Trust Units.

For Freehold investors in the $10.00 per Trust Unit initial public offering in November 1996, the Adjusted Cost Base of Trust Units still held as at December 31, 2002 is $4.6026 per Trust Unit, taking into account the return of capital of $5.3974 ($0.98 in 1997, $0.85 in 1998, $0.76 in 1999, $1.29 in 2000, $0.9672 in 2001, and $0.5502 in 2002).

SHARE CAPITAL

The Trust is authorized to issue an unlimited number of Trust Units. As at December 31, 2002, there were 30,225,236 Trust Units outstanding.

DISTRIBUTION POLICY AND DATES

The Trust makes monthly distributions, the amounts of which are determined by the Board of Directors, and are subject to change depending upon the business environment. Record dates are the end of each month, and payment dates are the 15th day of the following month.

UNITHOLDER PLANS

Direct Deposit Plan: A Direct Deposit Plan is in place to provide Unitholders who have Canadian bank accounts with a method of receiving cash distributions as a direct deposit into their bank account.

Distribution Reinvestment Plan (DRIP): A DRIP is in place to provide Unitholders who are residents of Canada with a method of reinvesting cash distributions into new Trust Units.

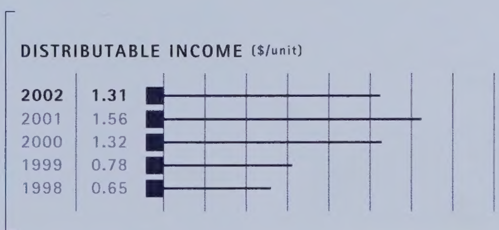
U.S. Currency Payment Plan: Unitholders may elect to receive their distribution payments in U.S. funds.

TRANSFER AGENT

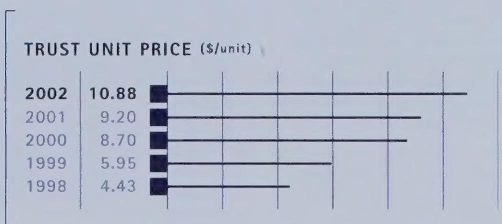
Registered Unitholders' change of address, duplicate mailings, lost Trust Unit certificates or distribution cheques, or general inquiries regarding the direct deposit, distribution reinvestment, or U.S. currency payment plans should be directed to:

Computershare Trust Company of Canada
600, 530 – 8 Avenue SW, Calgary, Alberta T2P 3S8
Telephone: (403) 267-6555
Fax: (403) 267-6592
Toll Free: 1-888-267-6555
Email: laura.leong@computershare.com
Website: www.computershare.com

Freehold distributed $39.5 million ($1.31 per Trust Unit) to Unitholders in 2002.



Closing the year at $10.88, the market value of Freehold Trust Units appreciated 18% from the end of 2001.



Acquisitions
The purchase of oil and/or natural gas properties for the purpose of generating revenues from their production.

Capital Expenditures
Investment of financial resources to develop proven reserves.

Development Well
A lower risk well drilled to produce proven reserves.

Differential
The difference between posted prices for light oil versus a heavier grade of oil.

Distributable Income
The income after deduction of all cash expenses that is distributed among Unitholders. This amount is sensitive to oil and natural gas prices and production volumes.

Established Reserves
The sum of Proven Reserves plus 50% of Probable Reserves.

Exploratory Well
A higher risk well drilled in an area where oil and natural gas reserves have not been previously discovered or proven.

Freehold Title
Land in which a private owner holds the mineral rights.

Heavy Oil
Dense, viscous oil containing a high proportion of bitumen usually with a gravity of 21 degrees API or less.

Horizontal Drilling
Drilling a well that deviates from the vertical and travels horizontally through the production zone.

Investor Netback
Operating netback adjusted for all other cash expenditures and receipts which results in the final net amount distributed to Unitholders.

Lease
An agreement where the owner of the mineral rights grants another party the right to drill for and produce oil and natural gas in exchange for payment of a royalty.

Lessee
A party that has acquired a lease from the owner of the mineral rights to drill for and produce oil and natural gas. The lessee is normally responsible for all related expenses including the payment of the lessor's royalty.

Lessor
The title owner of mineral rights, which could include the Crown, an individual or an entity.

Light Oil
Low density oil which has a gravity of 30 degrees API or higher.

Mineral Title
Ownership of rights to specified minerals.

Natural Gas Liquids (NGLs)
Liquids obtained from natural gas production and processing, including ethane, propane, butane and condensate.

Net Asset Value
The value of the Trust's assets including oil, natural gas, and potash reserves, undeveloped land and financial assets less its liabilities.

Net Production
The remaining share of oil or natural gas production after payment of royalties.

Operating Costs
Expenses incurred to recover oil or natural gas from a well exclusive of capital expenditures.

Operating Netback
The amount realized from the sale of a barrel of oil equivalent after deduction of operating costs and royalties.

Operator
The company or individual responsible for managing and conducting an exploration, development or production operation.

Potash
A mineral primarily comprised of potassium chloride used in the manufacturing of fertilizer.

Probable Reserves
Oil and natural gas reserves believed to exist with reasonable certainty on the basis of technical information.

Production
The volume measure of oil and natural gas produced from a well.

Production Unit
An arrangement under which a field or pool of oil or natural gas is to be operated as a common unit without regard to the boundaries imposed by lease ownership. This is done to maximize the economic benefits to all lease owners.

Proven Reserves
Oil and natural gas in known reserves that can be recovered with a great degree of certainty under existing technological and economic conditions.

Reserve Life Index (RLI)
A measure of the estimated life of Established Reserves by dividing year-end remaining reserves by the production during that year.

Royalty
The lessor's share of production revenues.

Royalty Lands
Lands which generate royalty income to their mineral rights holder, free and clear of any costs of production.

Shut-in Reserves
Proven oil and natural gas reserves which are not on production for reasons such as uneconomic conditions, remoteness of location or pending the completion of facilities.

Trust Unit
Units of the Trust, each unit representing an equal undivided beneficial interest therein.

Unitholder
Holders of Trust Units of the Trust.

Working Interest
The percentage ownership of a party in a lease which carries with it the rights and obligations to develop and operate an oil and natural gas property.

ABBREVIATIONS

AECO	reference pricing point for gas located at a gas storage facility near the Alberta-Saskatchewan border
API	American Petroleum Institute
ARC	Alberta Royalty Credit
bbl	barrel
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf = 1 bbl)
boe/d	barrels of oil equivalent per day
mbbls	thousand barrels
mboe	thousands of barrels of oil equivalent
mcf	thousand cubic feet
mmcf	million cubic feet
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
WTI	West Texas Intermediate

BOARD OF DIRECTORS

William W. Siebens[2]
D. Nolan Blades[1, 2]
Harry S. Campbell, Q.C.
Tullio Cedraschi
Dr. P. Michael Maher[1, 2]
Peter T. Harrison[1]
David J. Sandmeyer

1 Audit Committee
2 Corporate Governance & Nominating Committee

OFFICERS

William W. Siebens
CHAIRMAN

David J. Sandmeyer
PRESIDENT & C.E.O.

J. Frank George
VICE-PRESIDENT, EXPLOITATION

Joseph N. Holowisky
VICE-PRESIDENT FINANCE & ADMINISTRATION, C.F.O. AND SECRETARY

William O. Ingram
VICE-PRESIDENT, PRODUCTION

Michael J. Okrusko
VICE-PRESIDENT, LAND

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AUDITORS

KPMG LLP
CALGARY, ALBERTA

BANKER

Canadian Imperial Bank of Commerce
CALGARY, ALBERTA

EVALUATION ENGINEERS

Trimble Engineering Associates Ltd.
CALGARY, ALBERTA

ANNUAL INFORMATION FORM (AIF)

Copies of the AIF are available by contacting the Trust.

INVESTOR RELATIONS CONTACT

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Toll Free: 1-888-257-1873
Email: ir@freeholdtrust.com

THE ANNUAL MEETING OF UNITHOLDERS will be held on Wednesday, May 7, 2003 at 3:30 p.m. in the Lecture Theatre, Sunlife Plaza Conference Centre, Plus 15 (2nd level), 140 – 4th Avenue S.W., Calgary, Alberta.

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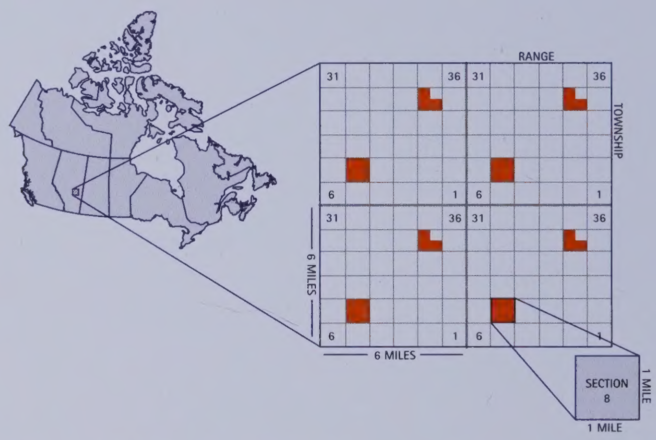
THE ROYALTY LANDS

Typical configuration of HB Lands after Confederation



A PIECE OF CANADIAN HISTORY

Unitholders share in a piece of Canadian history through their ownership of Trust Units in Freehold Royalty Trust.

1670
The Company of Adventurers

Charles II, King of England, granted to the Hudson's Bay Company all of the lands, including mineral rights, draining into the Hudson's Bay. This grant covered 1.5 million square miles, nearly 40% of Canada today.

1867
Confederation

Hudson's Bay Company surrendered its title in these lands to Canada (the Crown) and retained the right to hold, in perpetuity, 1/20th of the land in western Canada. This grant, which included all mineral rights, amounted to 7 million acres comprising Section 8 and three-quarters of Section 26 (the 8s and 26s) in most Townships south of the North Saskatchewan River (HB Royalty Lands).

1926
Hudson's Bay Company

Hudson's Bay Oil and Gas Company Limited (HBOG) and its partners received an exclusive right to lease all Hudson's Bay Company lands in western Canada to explore for oil and gas.

1973
Siebens Oil & Gas Ltd.

Hudson's Bay Company sold its interest in 4.6 million acres of mineral title lands to Siebens Oil & Gas Ltd.

1979
Canpar Holdings Ltd.

Canpar Holdings Ltd. and Dome Petroleum Limited acquired the assets of Siebens Oil & Gas Ltd. As a result, Canpar held approximately 25% of the original HB Royalty Lands. Canpar is a private company owned by the CN Pension Trust Fund – the pension fund for employees of the Canadian National Railway Company.

1996
Freehold Royalty Trust

Freehold Royalty Trust purchased the producing royalty lands from Canpar in conjunction with the Trust's initial public offering. This represented approximately 15% of the original HB Royalty Lands. Canpar retained the deep rights.

2003
Freehold Royalty Trust Today

Since inception of the Trust in 1996, Freehold has continued to acquire royalties. The Trust now holds mineral title and gross overriding royalty interests in over 805,000 gross acres in western Canada, representing 80% of its total land holdings. The mineral titles are particularly valuable to the Trust, as the rights are held in perpetuity. The CN Pension Trust Fund, with 31% of the outstanding Trust Units, is the largest Unitholder of Freehold.

Freehold
ROYALTY TRUST

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